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6.6 ROD CONTROL SYSTEMS

Learning Objectives :

1. State the purpose(s) of the Reactor Manual Control System, Rod Worth Minimizer, Rod Sequence Control System, Rod Block Monitoring System, and the Rod Control and Information System

2. Explain how control rod motion is achieved with the Reactor Manual Control System and the Rod Control and Information System.

3. State the major advantages the Rod Control and Information System has over the Reactor Manual Control System.

4. List the types of rod blocks and when they are in effect for the Rod Worth Minimizer, Rod Sequence Control System, and the Rod Block Monitoring System.

6.6.1 Introduction

The Rod Control Systems for BWR/2 through BWR/5 product lines utilize a collection of systems to accomplish the same purposes as the Rod Control and Information System supplied with the BWR/6 product line. The collection of systems used include the Reactor Manual Control System, Rod Worth Minimizer System, Rod Sequence Control System, and the Rod Block Monitoring System. The purposes of the Rod Control System's are:

- Provide a means of changing core reactivity to change reactor power level and control flux distribution.

- Enforce rod patterns to limit rod worth and reduce the effects from rod drop accident or rod withdraw error.

6.6.2 BWR/2 Product Line

The BWR/2 product lines control rod worth and provide a means of changing core reactivity with the Reactor Manual Control System and the Rod Worth Minimizer System. Discussion of these systems are found in the paragraphs that follow.

6.6.2.1 Reactor Manual Control System

The Reactor Manual Control System (Figure 6.6-1) consists of the switches, relays, interlocks, alarms, and electrical equipment necessary to result in control rod movement. The RMCS provides the necessary sequence and timing signals to the directional control solenoid valves of the control rod selected for movement. Normal control rod movement is one notch at a time through the timing sequence, but continuous movement controls are provided. The basic inputs to the RMCS are manual via the rod select pushbuttons and rod movement control switches. Interlocks are provided to block the selection and/or movement of a control rod if plant conditions are abnormal. The major components of the Reactor Manual Control System are discussed in the paragraphs that follow.

Rod Select Matrix

The manual rod selection capability is provided by pushbutton type switches, one for each rod, arranged to the approximate geometry of the core. The push buttons are wired so that when one switch is depressed, control power is removed from all other rod select pushbuttons.

Rod Selection Relays

Energization of the rod selection relay indicates that the rod select pushbutton request has been honored and the control rod is allowed to selected for movement. For the selection to be honored select block interlocks must be satisfied.

Rod Control Relays

The rod control relays allow the request for rod movement to be transmitted from the rod movement control switches to the timer logic, if certain permissives are met. These permissives are termed "rod blocks" and are either insert or withdraw blocks.

Timer Logic

The timer logic provides the required signals to the directional control solenoid valves in the proper sequence and timing to cause the selected control rod drive to respond as requested by the operator.

Rod Movement Control Switches

Control rod drive movement request is accomplished through the use of two control switches, the control rod movement control switch and/or the emergency in notch override switch.

The control rod movement control switch is a three position switch; rod in, off, and rod out notch (spring return to off). Through the use of this switch the operator can initiate notch in and notch out cycles. Notch movement means moving a control rod from one even position indication to the next. If the switch is held in the rod out position, the control rod will complete one notch out cycle and stop. If the switch is held in the rod in position the control rod will continuously drive in until released.

The emergency in notch override switch allows the operator to make a continuous rod withdrawal when used simultaneously with the rod movement control switch. The emergency in position is provided to allow control rod selection if the timer logic is not available or wanted.

6.6.2.2 Rod Worth Minimizer

The Rod Worth Minimizer (RWM), Figure 6.6-2, serves as a backup to procedural controls to limit rod worth during low power operation so that the postulated rod drop accident will not exceed the allowed limit of 280 calories/gram. Table 6.6-1 provides additional information for other cal/gm values.

Rod movement sequences are developed to limit rod worth to a level below which, if a rod drop accident were to occur at a free fall rate limited by the velocity limiter, the enthalpy from the transient would be less than 280 calories/gram. Figure 6.6-3 shows rod worth curves relative to the danger level for unrestrained rod movement (curve A) and RWM restrained movement (curve B). Due to lower rod worth at power, the RWM is not needed to limit rod worth above 20% power. The major components of the RWM are the computer program and the operator's display panel.

The RWM is a computer monitoring system which minimizes control rod reactivity worth by blocking rod movement if the existing control rod pattern deviates from a specific sequence. The sequences are developed by the plant nuclear engineers and loaded into the RWM memory. Actual rod positions are obtained, for comparison to the sequence, from the Rod Position Information System.

Operating Sequence

The Rod Worth Minimizer program contains an operating sequence which is loaded into the computer memory. The operating sequence is a schedule to be followed by the plant operator when withdrawing or inserting control rods. The sequence identifies the control rod by XX-YY coordinates and the positions to which each rod should be withdrawn in going from shutdown to full power. When going down in power, the rods are inserted in the reverse order of their withdrawal. The operating sequence is sequentially subdivided into rod groups.

Each rod group consists of a number of specified control rods and a set of insert and withdraw position limits that apply to each rod in the group. The groups are numbered in the order in which they are to be withdrawn when going up in power. Each sequence generally begins by withdrawing approximately half the rods in the core to full out. Under cold conditions, this brings the reactor to the point of criticality and to heating power. The fully withdrawn control rods are distributed in a checker board (black and white) pattern. The remaining rods are subsequently withdrawn to either full out or intermediate positions in the order specified by the sequence.

Notch Error

All rods in groups higher than that in which the black and white pattern is achieved have notch control restraints superimposed on the normal group limits. This means that in addition to remaining within the groups limits, any rod contained in one of these notch control groups must also remain within one notch position of every other rod in the same group.

A notch error occurs whenever the reactor is operating in a rod group higher than that in which a black and white pattern is achieved and notch limits are violated (rods in a group are more that one notch apart).

Low Power Set Point

The low power setpoint is the core average power level below which the Rod Worth Minimizer program is active in forcing adherence to the operating sequence of rod withdrawals or insertions. When the core power level is above the low power setpoint, the program does not impose any rod blocks as a result of rod movement by the operator. The low power setpoint is set above the level of required enforcement (20% power) and is sensed by both total steam flow and total feedwater flow being greater than 30% of rated power.

Withdraw Error

A withdraw error can occur either when a rod contained in the current group or any lower group is withdrawn past the withdraw limit for the group, or if a rod contained in a group higher than the current group is withdrawn past the insert limit for the higher group.

Insert Error

An insert error occurs when a rod contained in the current group is inserted past the insert limit for this group, or if a rod contained in a group lower than the current group is inserted past the withdraw limit for the lower group.

Select Error

A select error occurs whenever the operator selects a rod other than one contained in the current rod group. The select error provides the operator with warning that he has selected a rod, which if moved, will create an insert or withdrawal error.

Operation

Control rods are withdrawn according to the operating sequence. The Rod Worth Minimizer sequence restraints require that the rod groups be pulled in sequential order to specific group limits. The control rods within a group may be pulled in any order. Some flexibility is permitted by allowing two insert errors before rod blocks are applied. One withdrawal error will cause a rod withdrawal block. The rod blocks are normally applied so that only rod movements to correct errors are allowed. Forcing the operator to make the necessary corrections before permitting further rod movement. Once the black and white pattern is obtained notch limits must be observed in addition to group limits. The rods within the group must remain within one notch position of every other rod in the group. A notch error exists if notch limits are violated resulting in rod blocks being applied forcing the correction of the notch error before rod movements can continue.

6.6.3 BWR/3 Product Line

The BWR/3 product line utilizes the same systems as the BWR/2 product line plus one additional system, Rod Block Monitoring System, for power operation greater than 30% power. The Rod Block Monitoring System prevents the operator from exceeding thermal hydraulic limits in a local region of the core for a single rod withdrawal error from a limiting control rod pattern. A limiting control rod pattern is defined as a pattern which results in the core being on a thermal hydraulic limit.

6.6.3.1 Rod Block Monitoring System

The Rod Block Monitoring (RBM) system is designed to prevent local fuel damage by generating a rod withdrawal block under the worst permitted LPRM detector bypass and failure conditions and under the worst single rod withdrawal error when starting from any permitted power and flow condition. This system prevents overpower around a control rod by blocking the withdrawal of that rod. This prevents: the local fuel bundles from approaching MCPR limits; local power from grossly exceeding the total core power limit; and local fuel damage, by supplementing the APRM trip functions.

The system monitors local power by generating a signal from the LPRMs in the four strings which surround the rod selected for movement. The RBM function, by analysis, is not required below 70 percent power. However, it is used whenever the reactor power is above 30 percent as indicated on the APRM channel which is assigned as a reference to each RBM Channel. The RBM setpoints are derived from the results of various transient analyses which are performed for each fuel cycle.

The system receives a "rod select" signal from the Reactor Manual Control system. It routes the LPRM outputs from the adjacent LPRM assemblies to the averaging circuit. The system increases the gain of the averaging circuit until its output equals, or exceeds, the reference APRM signal. The system then compares this signal to a flow-biased reference signal. A rod withdrawal block is generated if the averaged LPRM signal raises above the flow-biased trip reference signal.

Typically, there are two RBM channels. Each channel receives inputs from specified levels (A and C; or B and D) of LPRM detectors. There are three parallel trip reference levels which will be used for generating the rod block setpoints, as shown in Figure 6.6-4.

General Electric Nuclear Energy has instituted a new program identified as Average Power Range Monitor (APRM), Rod Block Monitor (RBM), and Technical Specifications Improvements. This program is called the ARTS program. The objectives of the ARTS program are to:

- Increase plant operating efficiency.
- Update thermal limits requirements and administration.
- Improve plant instrumentation responses and accuracy.
- Improve the man/machine interface involved in plant operation.

General Electric maintains that the above objectives are attained by making the following improvements:

- Implementing a power dependent minimum critical power ratio (MCPR) limit similar to that used by BWR/6.
- APRM trip setdown requirement is replaced by more meaningful limits to reduce the need for manual setpoint adjustments and to allow

direct limits administration.

- Flow-biased RBM trips are replaced with power dependent trips.

- RBM inputs from the LPRMs are assigned to improve the response characteristics and to produce trip percentage increases of initial signal, Figure 6.6-5 & 6.6-6.

- Rod withdrawal error analysis is performed to more accurately reflect the actual plant conditions.

With the introduction of ARTS, the APRM setpoint setdown factor is removed.

6.6.4 BWR/4 and BWR/5 Product Lines

BWR/4 and BWR/5 product lines added an additional system to the already existing systems being used to control rod movement by imposing rod block trip signals. The introduction of the BWR/4 product lines with a higher power density core required further studies in limiting rod worth. The studies indicated a new system was needed to backup the Rod Worth Minimizer because:

- The RWM had a poor reliability record.

- The RWM could fail in an unsafe manner.

- The RWM is easily bypassed.

The new system designed to be a backup to the RWM is the Rod Sequence Control System (RSCS).

6.6.4.1 Rod Sequence Control System

The Rod Sequence Control System (RSCS) restricts rod movement to minimize the individual worth of control rods to lessen the consequences of a rod drop accident. Control rod movement is restricted through the use of rod select, insert, and withdraw blocks. The RSCS is a hardwired, redundant backup system to the RWM. It is independent of the RWM in terms of inputs and outputs but the two systems are compatible.

The RSCS operation is divided into two modes of operation, with the black and white rod pattern being the division point. At less than a black and white rod pattern, the sequence control mode controls rod movement from rod full-in to the black and white rod pattern by imposing select blocks. The group notch control mode controls rod movement from the black and white rod pattern to 30% power by imposing rod withdrawal and insert blocks.

Sequence Mode Selector

The Sequence Control Mode controls rod movement from rods full in to the black and white rod pattern by imposing rod select blocks. These rods are divided into two rod groups which are compatible with Rod Worth Minimizer rod groups. From an all rods full in condition, the operator may choose either of the two groups to begin movement. Once the operator begins to withdraw the first rod in that group, the logic will not allow selection of any rods but those in the chosen group, until all rods in that group are moved to the full out position. When all rods in the second group are moved full out, the Rod Sequence Control System will move into Group Notch Control.

The sequence control logic makes decisions on the basis of inputs from the Control Rod Drive System. It provides only full in and full out position information for each control rod drive mechanism to the Rod Sequence Control System. This information is derived from redundant switches in the control rod drive mechanism position indicating probe and is not used for digital display or by the Rod Worth Minimizer.

The sequence control logic will not allow selection of out of sequence control rods for movement.

Group Notch Control Mode

The Group Notch Control Mode controls rod movement from the black and white pattern to the 30% power bypass, by imposing rod withdrawal and insert blocks. All control rods are assigned to notch control groups which are compatible with Rod Worth Minimizer rod groups.

Group notch control logic requires that all rods within a notch control group must remain within one notch. Once a rod is moved in either direction in a notch group, rod blocks are imposed on; (1) the initially moved rod to prevent further movement in the same direction, and (2) all other rods in that group to prevent movement in the opposite direction. After the initial movement, the logic is reset whenever all rods in the notch group are again at the same position. The logic consists of a set of memory units, one for each notch group. The memory units track the relative position of the rods in each group by sensing the rod selected, direction of movement requested, and the occurrence of the Reactor Manual Control System timer settle function. The logic output signals are applied to the Reactor Manual Control System as withdraw or insert blocks.

Comparison to RWM

The Rod Sequence Control System restraints are designed to be compatible with those of the Rod Worth Minimizer. Several differences in philosophy between the two systems are outlined below:

The Rod Worth Minimizer is more restrictive in the sequencing of rod movements.

The Rod Worth Minimizer applies restraints only after the operator has deviated from the operating sequence. The Rod Sequence Control System restraints are applied so that the operator is not allowed to deviate.

The Rod Worth Minimizer can be entirely bypassed manually by the operator. The Rod Sequence Control System has only limited manual bypass capability.

The Rod Worth Minimizer is computer software and can be changed by a programmer. The Rod Sequence Control System is completely hardwired.

Bypass Capability

The Rod Sequence Control System is not required to limit rod worth at greater than 20% reactor power. A system bypass signal is generated at a conservative level of 30%, as measured by a pair of pressure sensors which monitor the main turbine first stage pressure.

The circuitry does allow certain bypass capability. In the Sequence Control logic, the full in or full out position for each rod can be bypassed. This is necessary for certain surveillance tests. In the Group Notch control logic, each notch group memory has a reset button which will reset the memory regardless of the previous latch states.

NEDE-24011-P

In a letter of August 15, 1986 from T.A. Pickens, Chairman of the BWR Owners Group (BWROG), an Amendment 17 to General Electric Topical Report NEDE-24011-P (GESTAR II) was proposed and agreed to by the NRC. This submittal was a request to eliminate the required use of the Rod Sequence Control System (RSCS). The proposal stated better computers used by RWMs, lower peak fuel enthalpy from a rod drop accident, an existing NRC probability study demonstrating an extremely low probability for an event exceeding fuel damage criteria (10^{-12}), and RSCS elimination would reduce operational complexity (ATWS events). To date some plants, not all, have elected to eliminate the RSCS.

6.6.5 BWR/6 Product Line

The BWR/6 product line controls rod movement and rod worth with the Rod Control and Information system (RSCS). RC&IS consists of the electronic circuitry, switches, indicators, and alarm devices necessary to achieve control rod manipulation. To prevent inadvertent operator errors, reactor core performance and control rod positions are constantly monitored by systems that either give an alarm demanding operator attention or completely block rod movement until the error has been corrected. *The RC&IS includes interlocks that inhibit control rod moment, but does not include any of the circuitry or devices used to scram the reactor.*
RC&IS is comprised of four subsystems, (Figure 6.6-7):

- Rod Interface System (RIS)
- Rod Action Control System (RACS)
- Rod Gang Drive System (RGDS)
- Rod Position Information System (RPIS)

The RC&IS can be operated in either the gang drive or the individual drive mode. In the gang mode up to four control rod can be positioned at once. Discussion of the major components of the RC&IS are discussed in the paragraphs that follow.

6.6.5.1 Rod Interface System

The Rod Interface System (RIS) is a digital, time multiplexed, fixed program, special purpose computer comprised of an operator control module, rod display module, and auxiliary select module. Data to be displayed arrives at the RIS in the form of several multiplexed words originating in the RACS, Rod Action Drive System (RADS), and the Neutron Monitoring System. Several multiplexed words are entering every millisecond and are used to update the memory so that it is never greater than a few milliseconds old. Independently, the memory is being searched and transformed into the correct display for the operator.

6.6.5.2 Rod Action Control System

The Rod Action Control System (RACS) consists of two redundant channels. Each channel includes the rod pattern control function, rod motion inhibit logic, and the directional control valve timing functions. RADS receives requested control rod motion signals from the RIS and after checking for the correct rod pattern sequence and interlocks generates a motion command and hydraulic control unit identity signal for the RGDS.

Rod Pattern Controller

The purpose of the rod pattern controller is to limit the worth of any control rod to minimize the undesirable effects resulting from a rod drop accident or rod withdrawal error. The rod pattern controller is a dual channel system designed as a safety related system to enforce procedural controls by applying rod blocks before any rod motion can produce high rod worth patterns. Rod pattern controllers are hard wired and are not programmable except through the use of new electronic cards.

The rod pattern controller continuously monitors the operator's request for rod motion, checks the request against built in criteria and, if necessary, blocks the RC&IS from carrying out the request.

Rod Gang Drive System

The rod gang drive system contains an analyzer section that compares motion and hydraulic control unit identity signals from two channels of the RACS. A disagreement between the signals is displayed on a fault map for operator information.

If the signals agree, one signal is stored in memory while the other is sent to the transponders of the hydraulic control units as an enable signal. Transponders, one for each hydraulic control unit, contains circuits that decode the motion command signals and compare the identity address to their own. If the identities match, the hydraulic control unit responds to the operation action code for rod movement. The transponder acknowledge the command signal by sending a signal back to another comparator in the RGDS where the requested and operation being performed. If the identity and operation code do not agree, the operation is terminated and annunciated.

6.6.6 Summary

The Rod Control Systems for BWR/2 through BWR/5 product lines utilize a collection of systems to accomplish the same purposes as the Rod Control and Information System supplied with the BWR/6 product line. The collection of systems used include the Reactor Manual Control System, Rod Worth Minimizer System, Rod Sequence Control System, and the Rod Block Monitoring System.

Table 6.6-1 Fuel Enthalpy vs. Fuel Damage

Condition	Enthalpy of Fuel (cal/gm)
Cladding Perforation	170
Onset of UO_2 Centerline Melting	220
UO_2 Complete Melting	280
Instantaneous Fragmentation and Dispersal of Fuel Rods	425

Note: *Although UO_2 melting occurs if the fuel enthalpy reaches 280 cal/gm, relatively few fission products are released from the fuel cladding and the resulting pressure transient is minimal. The design limit is, therefore, based on 280 cal/gm.*

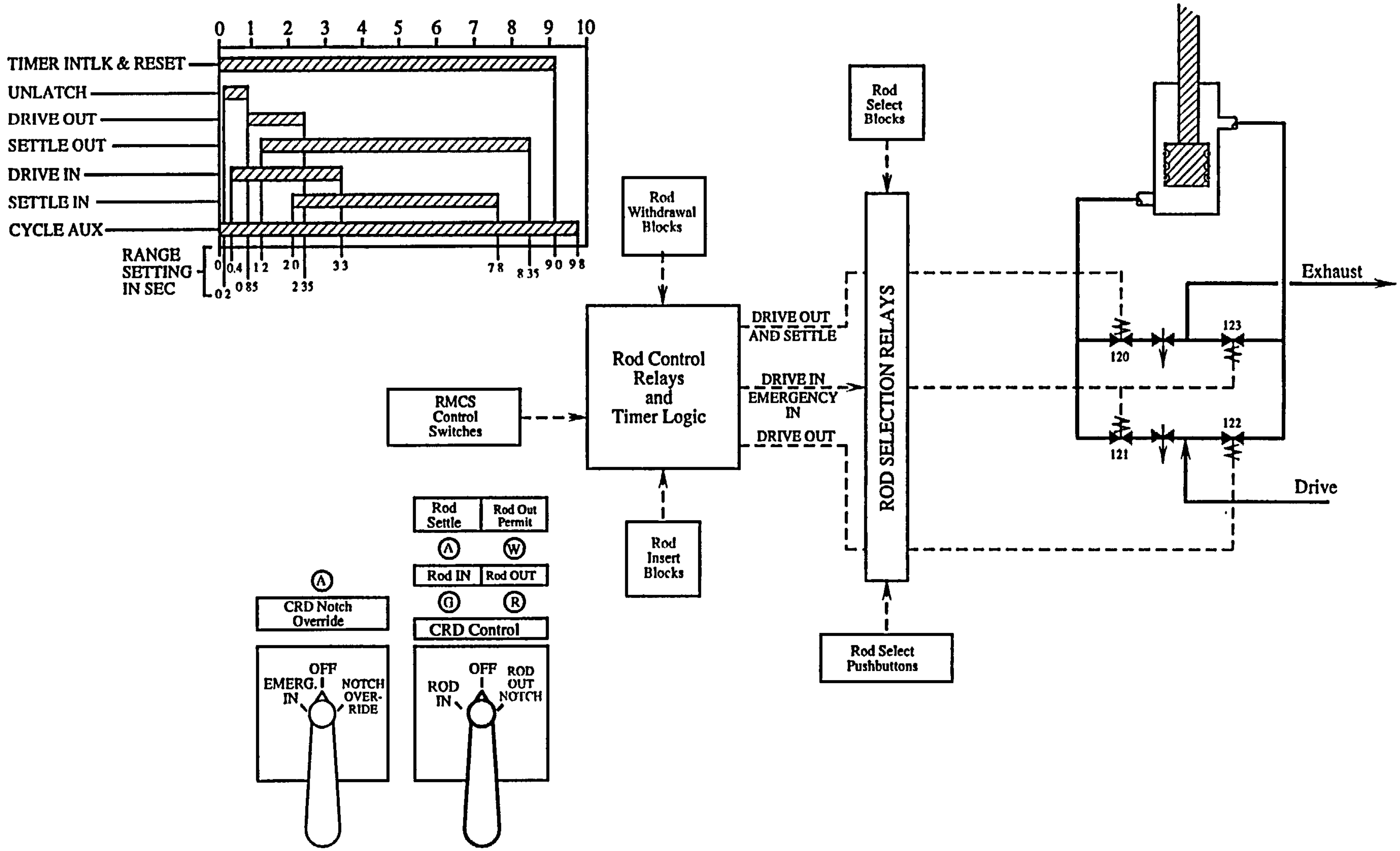

Figure 6.6-1 Reactor Manual Control System (BWR/2-5)

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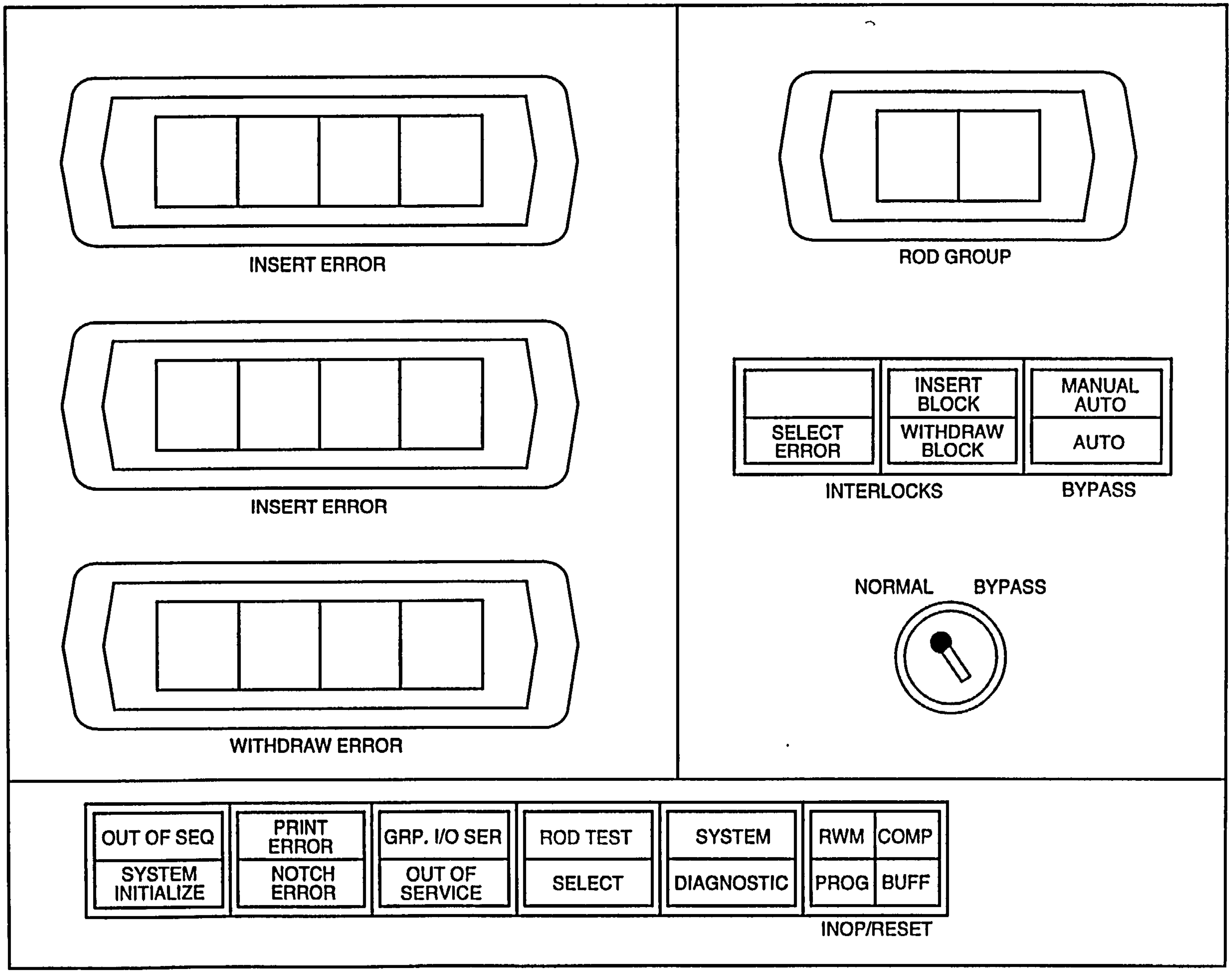

Figure 6.6-2 RWM Operator's Display Panel

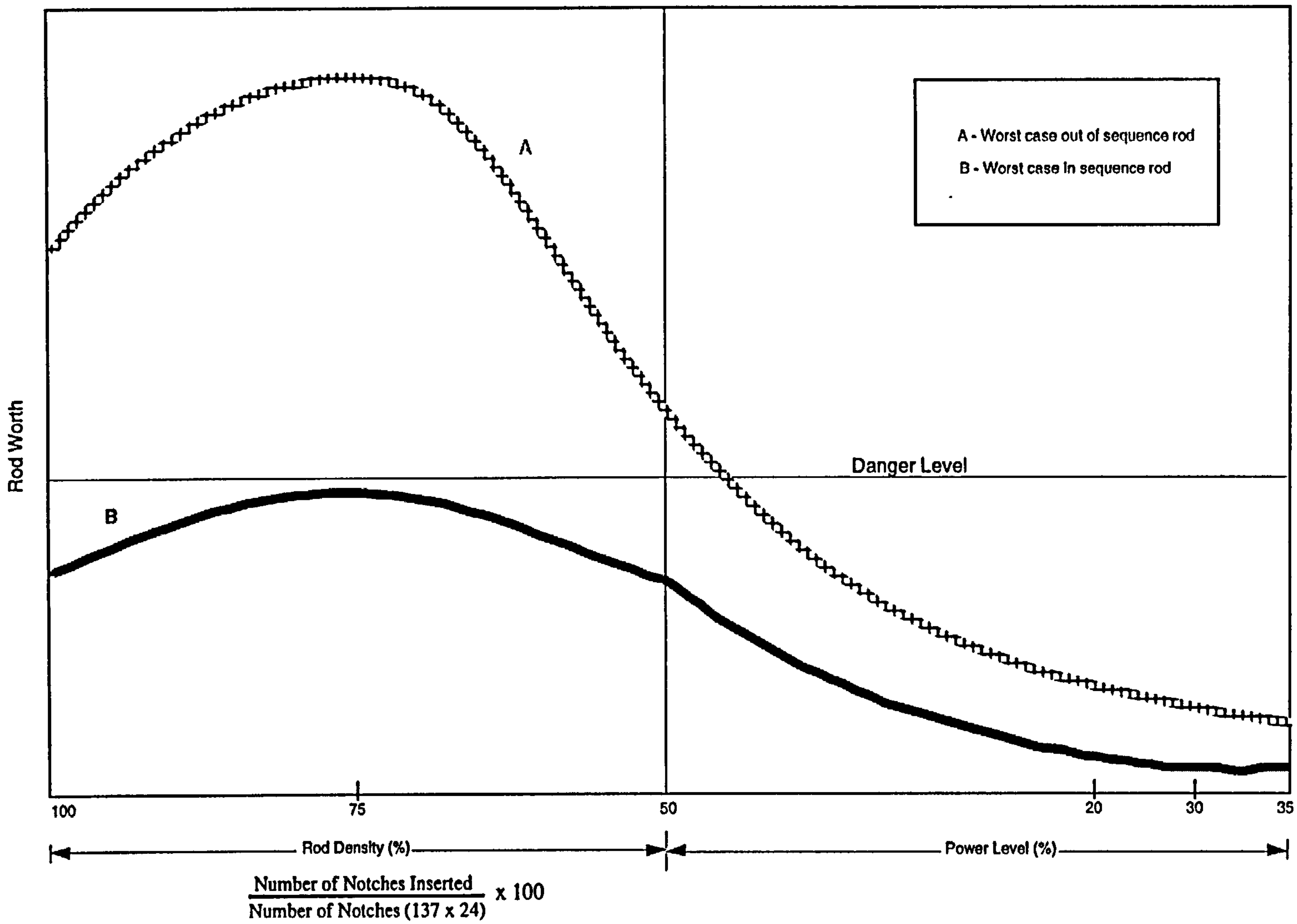

Figure 6.6-3 Rod Worth with Sequence and Notch Control Restraints

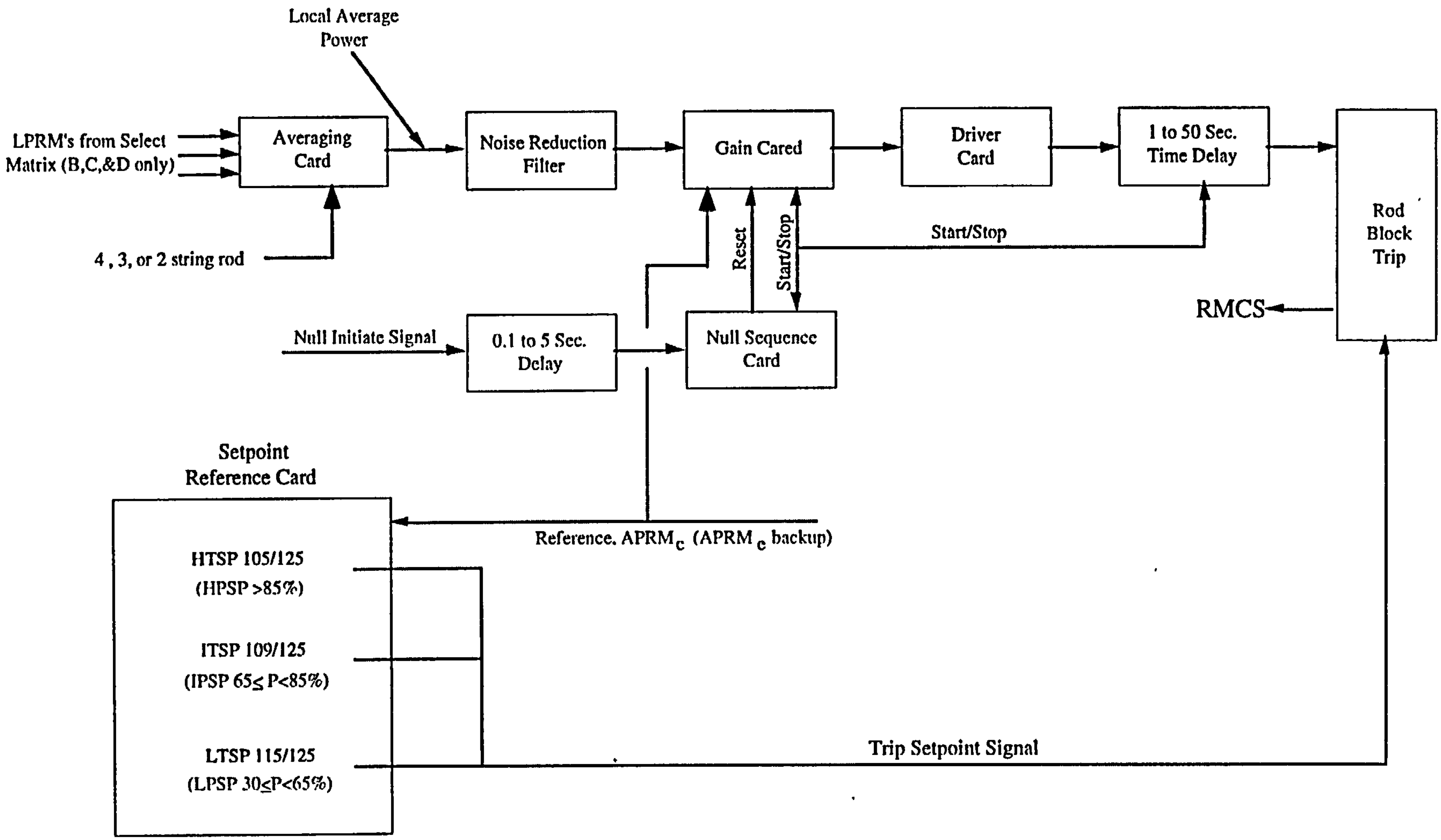

Figure 6.6-4 ARTS RBM (Channel "A")

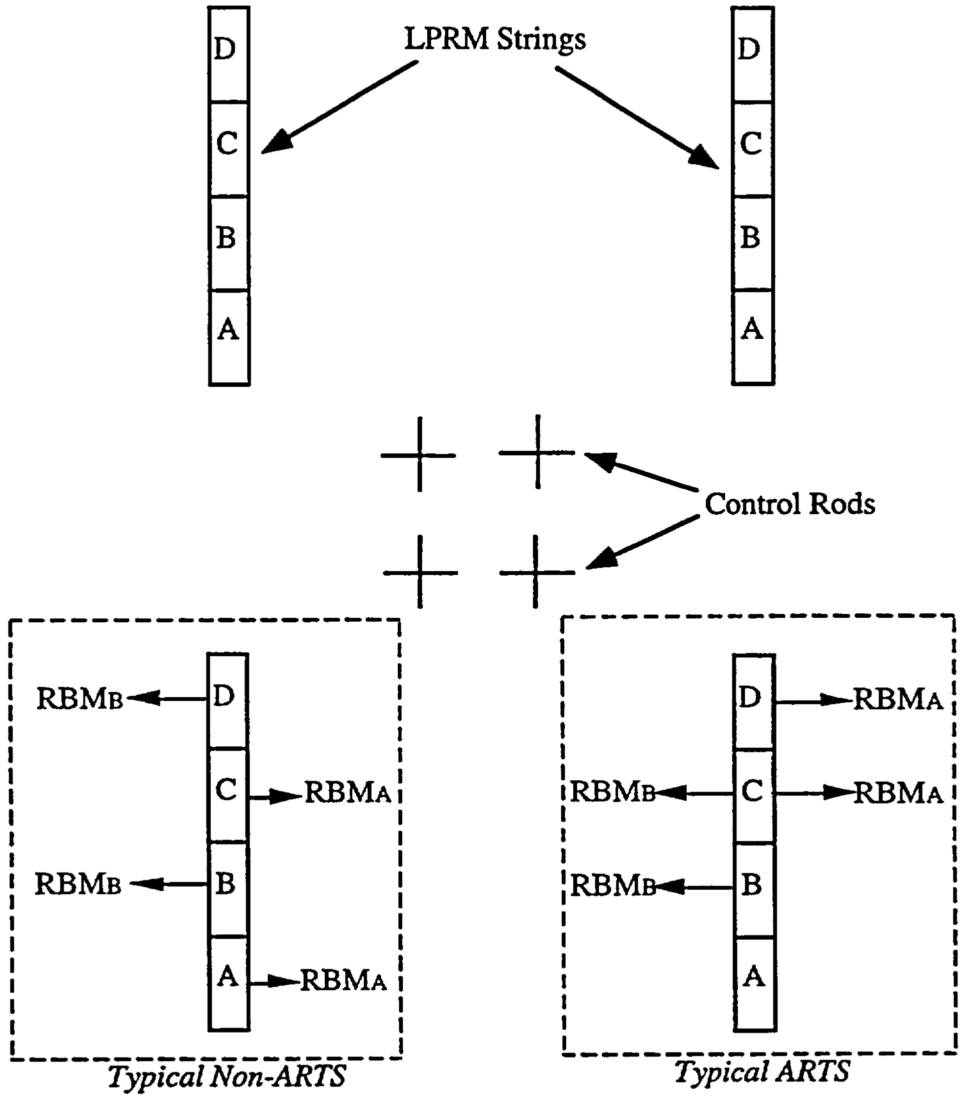

Figure 6.6-5 LPRM Assignment to RBM Averaging Ckt.

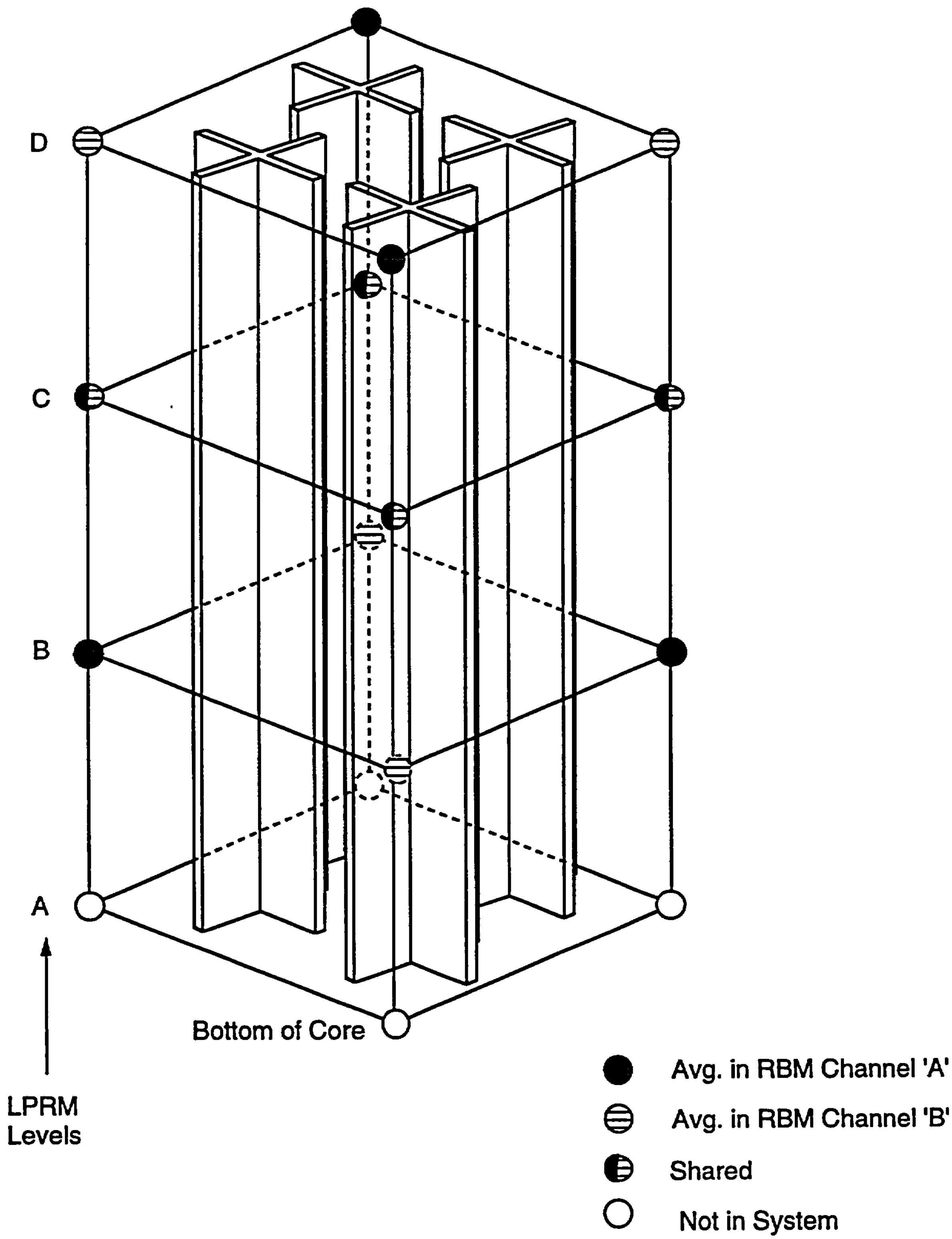

Figure 6.6-6 LPRM Assignment

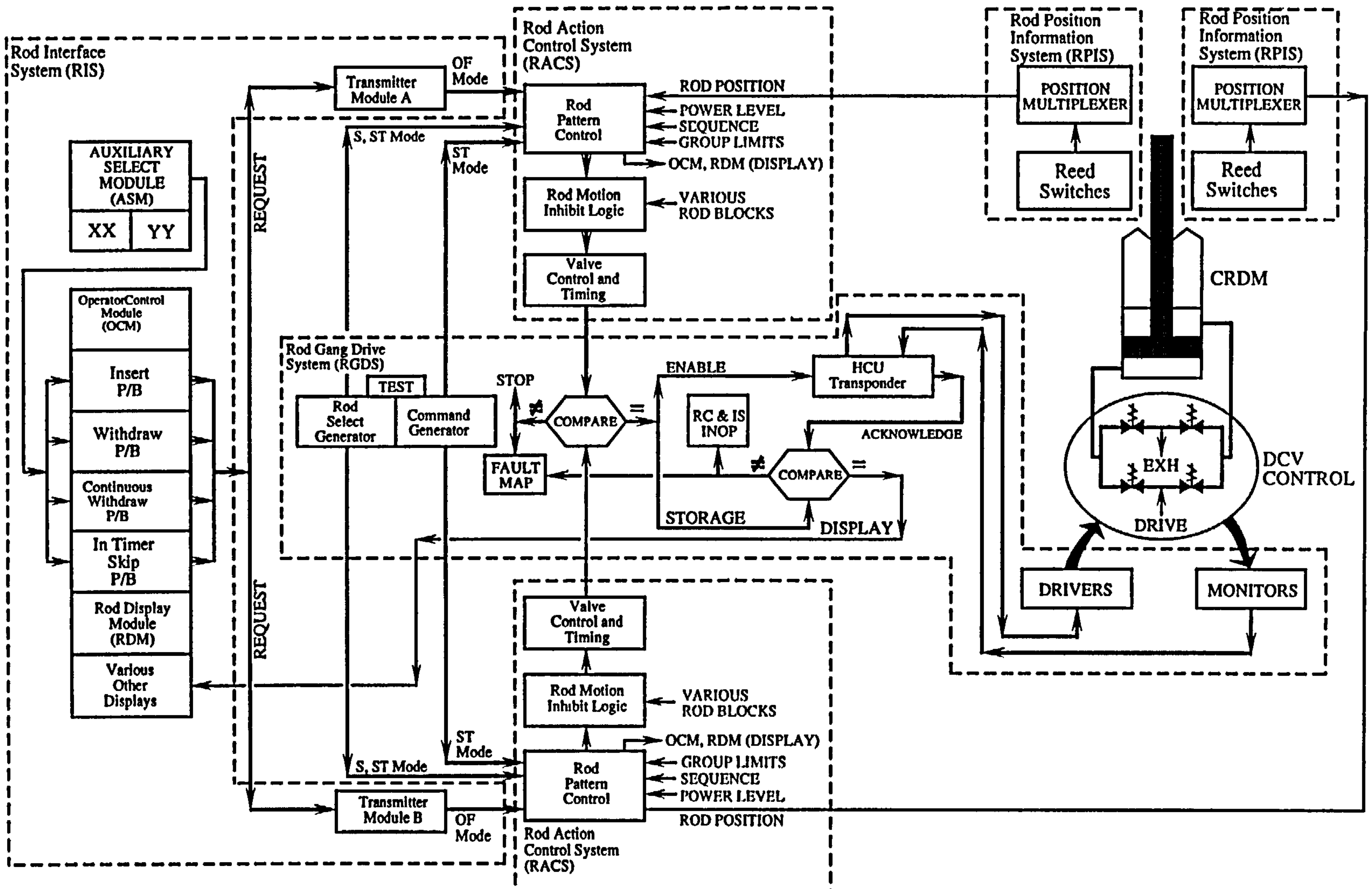

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Figure 6.6-7 Rod Control & Information System

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6.7 BALANCE OF PLANT SYSTEM

Learning Objectives :

1. Explain how water level is controlled with motor driven feedwater pumps.

2. Explain how and why pump runout protection is provided for motor driven feedwater pumps.

3. Explain how some of the feedwater control systems minimize level overshoot.

4. List the major differences found in condensate and feedwater systems.

6.7.1 Introduction

The discussion in this section is directed toward the condensate and feedwater system and the feedwater control system. Keeping in mind that the condensate and feedwater system is designed by the architectural engineer in concurrence with the utility; very few are the same. However, you will discover that all systems must have a means of delivering the water at sufficient pressure and volume to maintain reactor vessel water level during normal system operation. In addition, the condensate and feedwater system will cleanup and preheat the water prior to delivering it to the reactor vessel.

The feedwater control systems consists of two basic types with small variations to account for the specific condensate and feedwater system being controlled.

6.7.2 Condensate and Feedwater System

The two most common condensate and feedwater systems used differ in the type of feed pumps, feedwater heater arrangement, and the means of filtering and cleaning up the water.

6.7.2.1 Early Condensate and Feedwater System

The condensate and feedwater system, Figure 6.7-1, is an integral part of the plants conventional regenerative steam cycle. The steam exhausted from the three low pressure turbines is condensed in the main condenser and collected in the condenser hotwell, along with various equipment drains. The condensate is removed from the hotwell by three of the four condensate pumps. The fourth pump is a standby pump with an automatic start feature if one of running pumps should trip. The condensate pumps provide the driving force for the condensate which flows through the steam jet air ejector (SJAE) condensers and gland seal leak off (GSLO) condensers; to perform a heat removal function. At this point the condensate is directed to the condensate demineralizers to filter and demineralize the condensate. After the demineralizers, booster pumps increase the driving force for the condensate flowing through three parallel strings of low pressure feedwater heaters.

Each heater string is rated for 33% flow. Isolation of a string requires routing the flow through the bypass line around the heater string. This type of heater string arrangement yields a large and sudden decrease in feedwater temperature following heater string isolation. Decreasing feedwater temperature will cause reactor power to increase and the power distribution to peak in the bottom of the core.

The motor driven feedwater pumps take the preheated water and further increases the pressure to a value above reactor pressure. The amount of feedwater flowing to the reactor vessel is controlled by varying the position of the feedwater regulating valves.

The discharge of the feedwater regulating valves is directed to the high pressure feedwater heater strings for the final stage of feedwater heating. Two feedwater lines penetrate the primary containment and further divide into a total of four lines. Each of the four supply lines provide feedwater to its respective sparger. The feedwater spargers distribute the flow of feedwater within the vessel annulus area.

6.7.2.2 New Condensate and Feedwater System

The condensate and feedwater system, shown in Figure 6.7-2, is an integral part of the plant's conventional regenerative steam cycle. The steam exhausted from the three low pressure turbines is condensed in the main condenser and collected in the condenser hotwell along with various equipment drains. The condensate is removed from the hotwell by three condensate pumps. The condensate pumps provide the driving force for the condensate which flows through the (SJAE) condensers, steam packing exhauster condenser, and offgas condensers to perform a heat removal function. At this point the condensate is directed to the condensate demineralizers and through the process of ion exchange, impurities are removed. After the demineralizers, booster pumps increase the driving force of the condensate flowing through strings of low pressure feedwater heaters. The turbine driven, variable speed, feedwater pumps take the condensate and increase the pressure to a value above reactor pressure.

The amount of feedwater flowing to the reactor vessel is controlled by varying the speed of the turbine driven reactor feed pumps. The discharge of the feedwater pumps is directed to the high pressure feedwater heater strings for the final stage of feedwater heating. Two feedwater lines penetrate the primary containment and then further divide into a total of six lines which penetrate the reactor vessel. Each line supplies feedwater to its respective feedwater sparger. The feedwater spargers distribute the flow of feedwater within the vessel annulus area.

6.7.3 Feedwater Control System

The feedwater control system regulates the flow of feedwater to the reactor vessel in order to maintain reactor water level within the normal range during all modes of plant operation. The regulation of feedwater flow is accomplished by modulating the position of feedwater regulating valves or feed pump turbine speed. The feedwater control system measures and uses total steam flow, total feedwater flow, and reactor vessel water level signals to carry out its function.

Discussion of the two basic types of feedwater control systems are given in the paragraphs that follow.

6.7.3.1 Regulation of Feed Flow with Feedwater Regulating Valves

The feedwater control system (Figure 6.7-3) used to regulate the flow of feedwater via feedwater regulating valves has four modes of operation, each with a specific purpose.

Manual Operation

Used for feedwater control at low powers or for a water level problem.

Single-Element Operation

Used to control the low flow feedwater regulating valve and the normal feedwater regulating valves.

Three-Element Operation

Used to control the feedwater regulating valves.

Runout Flow Control

Allows the maximum feedwater flow possible without overloading or tripping the motor driven reactor feedwater pumps.

During normal operation the feedwater control system regulates reactor vessel water level by measuring different parameters:

- mass flow rate leaving the reactor vessel (steam),
- mass flow rate returning to the vessel (feedwater),
- and the mass inventory of water in the reactor vessel (level).

The three parameters are combined to develop a signal that is used to modulate the opening of the feedwater regulating valves.

During startups, shutdowns, and low power operation the rate of feedwater flow to the vessel is controlled by the low flow feedwater regulating valve.

6.7.3.1.1 Component Description

The components of this system are discussed in the paragraphs that follow.

Reactor Water Level Instrumentation

Reactor water level is measured by two independent level transmitters with a range of 0 to 60 inches. Only one of the two instruments may provide level signals to the FWCS at a time. Selecting either level A or level B instrument is accomplished via a level selector switch.

Total Steam Flow

Steam flow is calculated in each of the four steam lines by measuring the differential pressure across a flow restrictor. The calculated steam flow signals are sent to a four input summer which develops a total steam flow signal. The total steam flow signal is used as an input to the steam flow/feed flow summer, rod worth minimizer system and steam leak detection system.

Total Feedwater Flow

Feedwater flow is measured by venturi flow elements located in the two feedwater lines penetrating the drywell. The output signals from the flow transmitters are sent to a feedwater flow summer that generates a total feedwater flow signal. The total feedwater flow signal is used as an input to the steam flow/feed flow summer, rod worth minimizer system, flow integrator, RFC System, and the runout flow controller.

Steam Flow/Feed Flow Summer

The feedwater flow summer output (- signal) and steam flow summer output (+ signal) are sent to the steam flow/feed flow summer where they are summed to produce a base signal for the FWCS. If steam flow and feed flow are not equal, this summer will produce a signal either greater than or less than the base signal. The algebraic signs are such that when steam flow exceeds feedwater flow, the output signal will modify the level signal to indicate the need for additional feedwater flow. Thus, an anticipatory signal is developed which will correct for projected changes in level due to process flow changes. This anticipatory signal corrects feedwater flow to lessen the effect of changes on reactor level due to a change in steam demand.

Level/Flow Summer

The output of the steam flow/feed flow summer, a flow error signal, is compared with the selected reactor water level signal to produce an output signal referred to as the modified level signal. The flow error signal provides anticipation of the change in the reactor vessel water level that will result from a change in load. The level signal provides a reference for any mismatch between the steam flow and feed flow that causes the level to rise or fall.

Master Level Controller

The master level controller is provided to control either or both feedwater regulating valves to achieve the desired feedwater flow. Both single element and three element control modes of operation are available as determined by the mode selector switch.

Feedwater Regulating Valve Control

The feedwater regulating valves are positioned by valve operators. Air is supplied by a valve positioner to both the top and bottom on the valve operator diaphragm. Increasing the air pressure to the top and decreasing the air pressure on the bottom of the diaphragm causes the valve to close. The positioner output is controlled by a 3-15 psig air signal from the E/P converter. The E/P converter output is controlled, in turn, by an electrical signal from the FWCS controllers.

Runout Operation

The runout flow control network is provided to prevent tripping a reactor feed pump on overcurrent or low suction pressure due to an abnormally high flow. The flow through each of the three RFPs is monitored by devices called alarm units. If one or more RFPs exceed the alarm unit setpoint (5.6×10^6 lbm/hr), a RFP runout relay is energized. The runout relays control the AA solenoid and is energized only when two RFPs are running. The BB solenoid is energized if a runout condition is sensed by the runout relay.

Energizing the BB solenoid removes the M/A transfer station(s) from control and places the runout flow controller in the control circuit. The runout relay also causes the feedwater regulating valve bypass valve to close.

The runout flow controller compares a fixed setpoint with the total feedwater flow. If the total feedwater flow is greater than the fixed setpoint, a negative error signal is generated. The integrator output decreases and the feed regulating valves close until the feedwater flow matches the maximum setpoint allowed. The runout relay resets automatically when level indication increases to 20 inches. Manual reset of the runout relay is allowed if level is below 20 inches provided that the runout condition is not present.

Scram Response Operation

Feedwater systems with feedwater regulating valves or slow responding turbine driven feedwater pumps tend to over fill the reactor vessel following a scram. To counteract this effect, the FWCS reduces the level demand signal by 50% following a scram. The master controller output is returned to its normal demanded value upon resetting the reactor scram.

6.7.3.2 Regulation of RFPTs

The FWCS controls reactor water level low enough to minimize carryover, a condition that entrains moisture in the steam leaving the reactor vessel. Conversely, the FWCS controls water level high enough to minimize carryunder, a condition in which steam is entrained in the reactor vessel annulus water.

Reactor water level is measured by three independent sensing networks, each consisting of a differential pressure transmitter connected to a water reference condensing chamber leg located in the drywell. Feedwater mass flow rate is measured by flow transmitters coupled across flow elements in the feedwater lines. Total feedwater flow rate, as used by this system, is the sum of the signals from the feedwater lines. Steam mass flow rate through each of the steam lines is measured by differential pressure transmitters connected across the steam flow elbow tap in each steam line. The steam flow signals are summed before being used by the feedwater control circuit.

The FWCS, Figure 6.7-4, generates a signal that is used to regulate the position of the turbine speed control steam supply valves, thereby controlling the pumping effort of the turbine driven reactor feed pumps. The FWCS also generates the control signal that is used to position the reactor fill valve and the discharge throttle valve bypass (DTVB) during low power operation.

6.7.4 Summary

Condensate and feedwater systems are designed by the architectural engineer in concurrence with the utility; very few are the same. However, all systems must have a means of delivering the water at sufficient pressure and volume to maintain reactor vessel water level during normal system operation. In addition, the condensate and feedwater system will cleanup and preheat the water prior to delivering it to the reactor vessel.

The feedwater control systems consists of two basic types with small variations to account for the specific condensate and feedwater system being controlled.

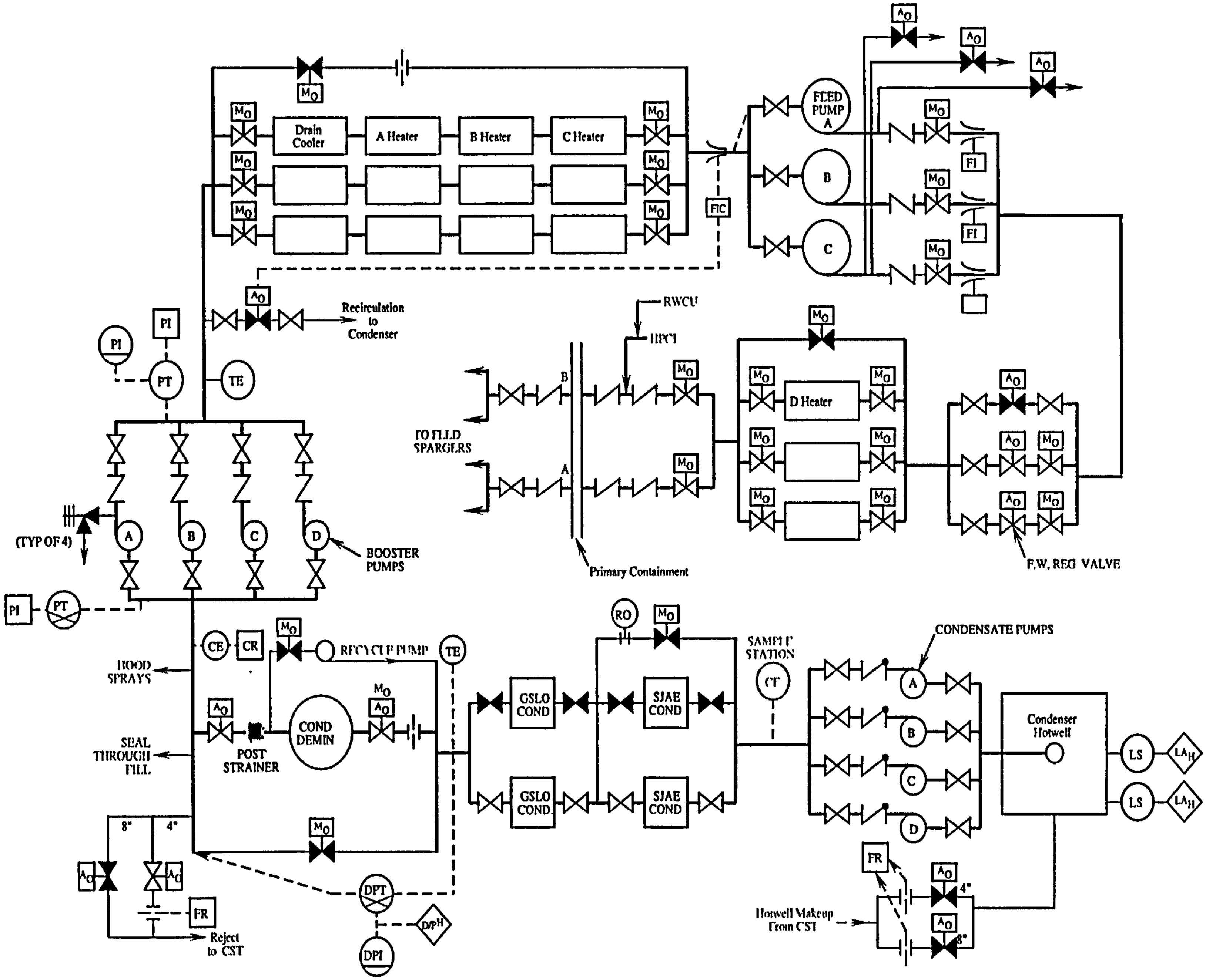

Figure 6.7-1 Condensate and Feedwater System BWR/3

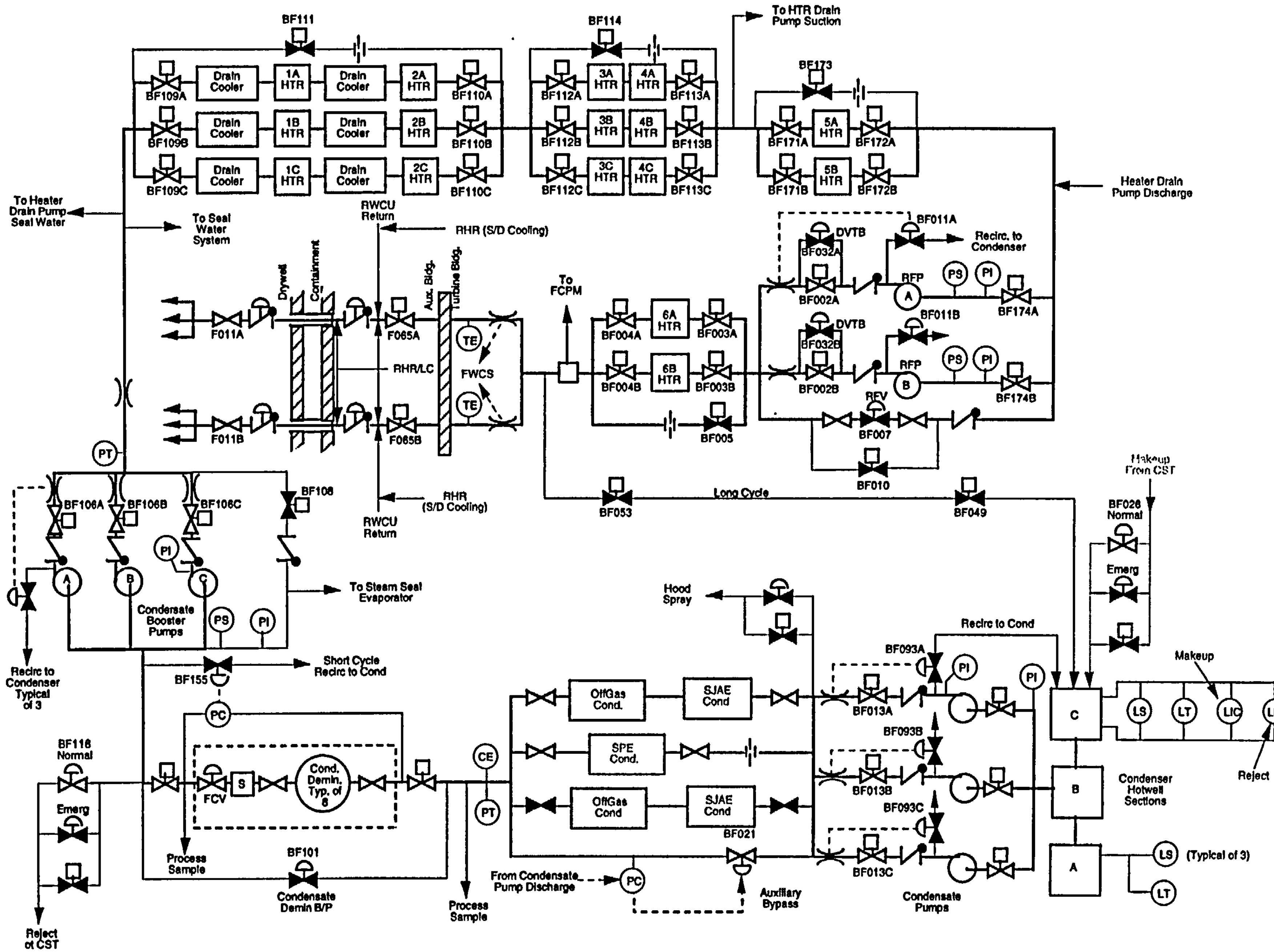

Figure 6.7-2 Condensate and Feedwater System BWR/4

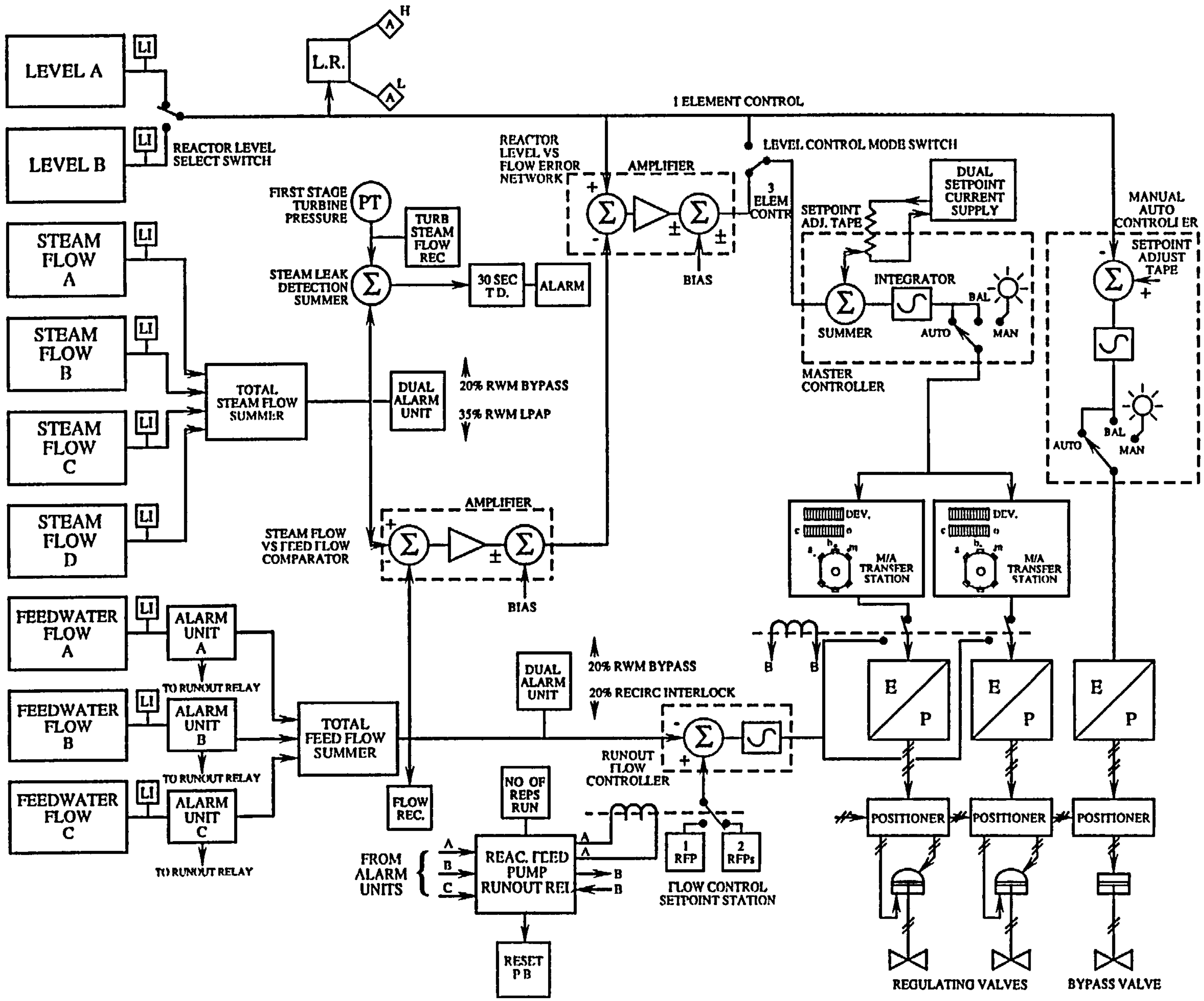

Figure 6.7-3 Feedwater Control System for Motor Driven Feed Pumps

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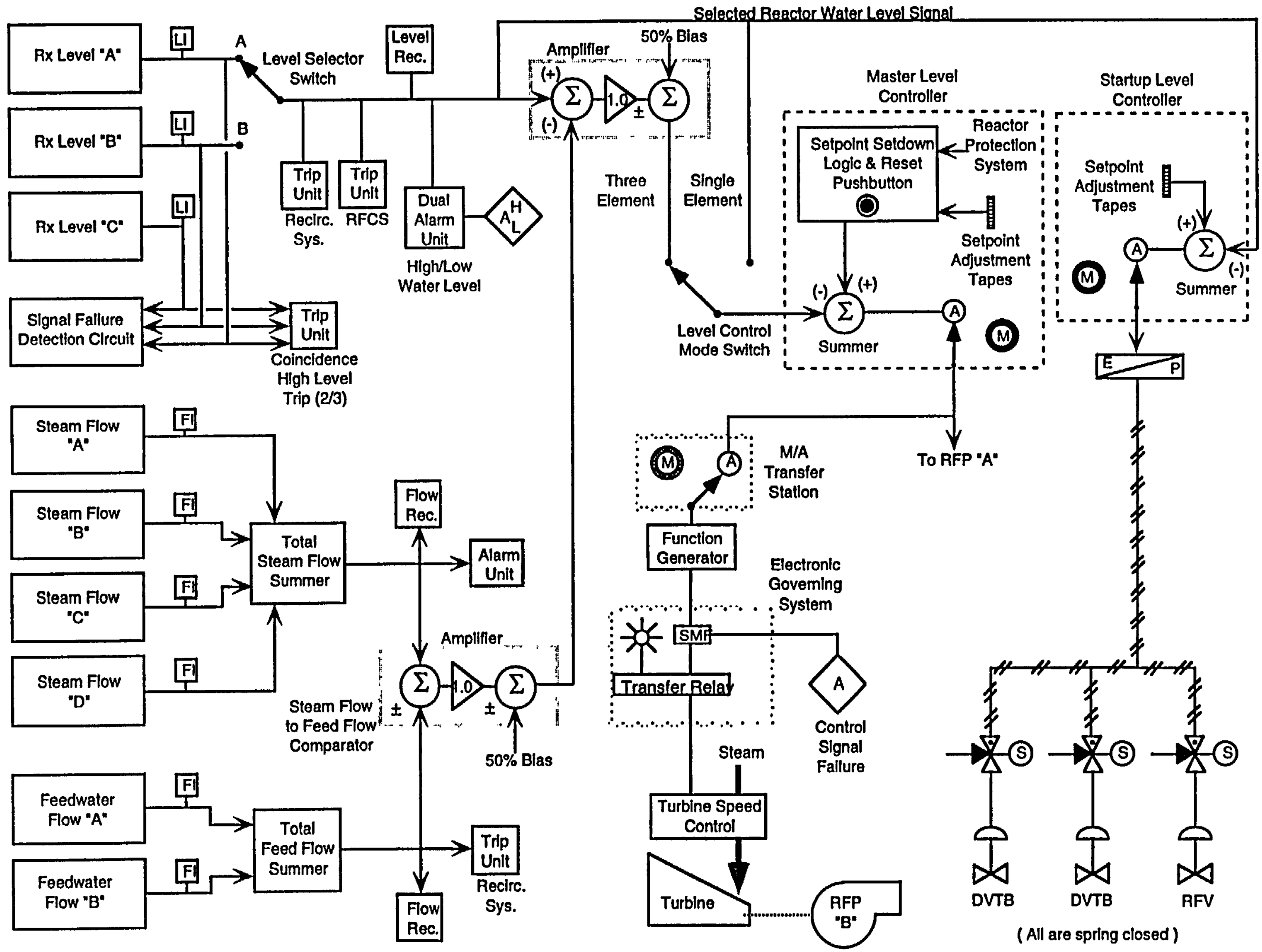

Figure 6.7-4 Feedwater Control System for Turbine Driven Pump

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6.8 SAFETY RELIEF VALVE DIFFERENCES

6.8.1 Introduction

The discussion in this section is directed toward the various safety relief valves (SRVs) used throughout the BWR product lines. Safety relief valves prevent over pressurization of the nuclear process barrier from abnormal operational transients. In addition to providing overpressure protection, a selected number of SRVs are used by the automatic depressurization system to rapidly decrease reactor pressure during specific small break loss of coolant accidents.

6.8.2 Two Stage Target Rock SRV

The two stage target rock SRV consists of two principle assemblies, a pilot valve section (top works) and the main valve section (bottom works). The pilot valve section (first stage) provides the pressure sensing and control element while the main valve (second stage) provides the pressure relief function.

The first stage consists of a pilot stabilizer disc assembly with a means for remote actuation, via the attached pneumatic actuator. The pilot valve is the pressure sensing member to which the stabilizer disc movement is coupled. Though not mechanically connected, a small spring (pilot preload spring) keeps the stabilizer in contact with the pilot. The setpoint adjustment spring permits setpoint adjustment (lifting pressure) of the pilot valve and provides pilot valve seating force. The second or main stage consists essentially of a large valve which includes the main valve disc, main valve chamber, main valve preload spring, and piston.

When the reactor is at operating pressure, below the setpoint of the valve, the pilot valve is seated with system pressure acting on the stabilizer disc side (Figure 6.8-1). The second stage of the valve has system pressure on both sides of the main valve piston with the main valve disc seated (closed). As system pressure increases to the setpoint of the SRV (Figure 6.8-2), the pressure acting on the pilot valve produces a force great enough to overcome the opposing force of the setpoint adjustment spring and lifts the pilot valve from its seat. As the pilot valve moves to full open (to the right), the stabilizer disc follows the pilot until the stabilizer is seated. With the pilot valve full open and the stabilizer seated, the area above the main valves piston is vented to the discharge piping via the main valve piston vent passage. This venting creates a differential pressure across the main valve piston, system pressure below the piston and drywell pressure above, causing the main valve to lift (open). The main valve piston is sized such that the resultant opening force is greater than the combined spring load and hydraulic seating force. The stabilizer disc is designed to control the valve blowdown and reset pressure, by holding the pilot open until the proper reclosing pressure is reached. The stabilizer chamber is connected, by a passage, to the inlet side of the main valve. The stabilizer disc will seat when the pilot lifts. The differential pressure across the stabilizer disc is sufficient to hold the pilot open; however, as system pressure decays, the differential pressure across the stabilizer disc decreases until the setpoint adjustment spring becomes the controlling member causing the pilot valve to reseat. Once the pilot valve has reseated, leakage of system fluid past the main valve piston and the stabilizer disc repressurizes the main valve chamber.

When steam pressure equalizes across the main valve piston, the opening force is cancelled and permits the main valve spring and hydraulic flow forces the main valve to close. Once closed, the additional hydraulic seating force, due to system pressure acting on the main valve disc, seats the main valve tightly and prevents leakage.

In the relief mode of operation, pneumatic pressure is applied to an air actuator by energizing a solenoid valve. The actuator mechanically positions the pilot assembly to the right, depressurizing the top of the main valve piston causing the main valve to open. The solenoids are energized by switches located in the control room. This type of arrangement provides the control room operator with a means of operating any of the SRVs remotely from the control room.

6.8.3 Three Stage Target Rock SRV

The three stage target rock safety relief valve (Figure 6.8-3) is similar to the two stage SRV with the exception of the upper works. The three stage SRV upper works consists of a pilot section, second stage assembly and pneumatic actuator assembly.

When reactor pressure is at operating pressure, below the setpoint of the valve, the pilot valve is seated by action of the pilot preload and setpoint adjustment spring. The main valve piston is held close by the main valve preload spring exerting a downward force on the main valve piston.

An increasing system pressure opens the pilot valve (Figure 6.8-4&5) by exerting a hydraulic force on the pilot valve bellows, which moves it to the right. Opening the pilot valve allows system pressure to be felt on top of the second stage piston. When pressure above the second stage piston is sufficient to overcome the upward force of the second stage preload spring, the second stage valve is forced downward, opening the valve. When the second stage valve opens it allows the pressure on top of the main valve piston to vent through the second stage relief passage and into the SRV discharge. Venting the pressure on top of the main valve piston forces the main valve assembly upward. The main valve piston is sized such that the resultant opening force is greater than the combined spring load and hydraulic seating force. The pilot preload and setpoint adjustment spring is designed to control valve blowdown and reset pressure by holding the valve open until the proper reclosing pressure is reached. When system pressure decays, the pilot preload and setpoint adjustment spring forces the pilot stem to the left against the pilot valve, causing it to close. The closure of the pilot valve allows system pressure to leak past the second stage piston and into the second stage relief passage. The second stage preload spring will lift the second stage valve, closing the valve. Once the second stage valve closes, the main valve piston chamber equalizes with the aid of the drilled passage in the main valve piston. When the main valve preload spring and the pressure above the main valve piston are greater than the pressure below, the main valve will close.

In the relief mode of operation, pneumatic pressure is applied to an air actuator by energizing a solenoid valve. The actuator mechanically positions the second stage valve by exerting a downward force on top of the piston assembly, depressurizing the top of the main valve piston causing it to open. The solenoids are energized by remote switches which allow the control room operator or a pressure switch to operate the valve.

The bellows portion of the pilot assembly ensures operation of the relief mode. If the bellows were to fail, insufficient pressure would exist to open the pilot valve. Therefore, a bellows failure alarm is connected to the area external to the bellows.

6.8.4 Dickers SRV

The Dickers type SRV, shown in Figure 6.8-6, is a spring loaded, sealed bonnet, angled, globe valve with an externally attached pneumatic operating cylinder. The operating cylinder is so arranged that a malfunction cannot prevent the valve from opening to satisfy the safety function. The major parts of the valve are the inlet nozzle, disc, disc holder, spindle, belleville washers (spring), bellows, balancing piston, bonnet, and pneumatic operating cylinder.

The inlet nozzle provides an opening for steam into the valve. The valve disc seats against the top of the nozzle with steam pressure beneath. The disc holder connects the disc to the spindle and provides for an easy removal of the disc during maintenance. The spindle applies the downward loading of the compressed belleville washers to the valve disc and is used to lift the valve disc when the pneumatic operator is used. The bellows provide a seal between the main body of the valve and the bonnet to prevent steam leakage into the bonnet when the disc is in the raised position. This seal prevents back pressure from affecting the spring setpoint. A back pressure balancing piston is also provided on the valve spindle so that valve opening pressure is not affected even if a bellows leak develops. Steam can leak past the balancing piston only in the event of a bellows rupture and then only when the valve is open and passing steam. The bonnet prevents steam leakage into the drywell when the valve lifts. The bonnet is vented to the suppression pool between the weir wall and the drywell. Each of these vent lines has a check valve to serve as an antisiphon vacuum breaker.

The pneumatic operating cylinder physically lifts the valve disc against spring force to open the valve. By this means, the SRV can be operated at any steam pressure down to 0 psig. The safety/relief valves are designed to operate in a post accident environment.

6.8.5 Crosby SRV

The Crosby SRV operates identical to the Dickers SRV. Crosby SRVs utilize a spring to provide the force that must be overcome for the valve to open instead of the belleville washers used by the Dickers valves.

6.8.6 Electromatic Relief Valve

Electromatic relief valves are provided to prevent lifting of the safety valves on early BWR product lines. The electromatic relief valves (Figure 6.8-7) are actuated by the solenoid assembly. Steam enters from chamber (A) and passes upward around disc guide to chamber (B). Steam enters chamber (C) through clearance space between the main valve disc and disc guide. The main valve is held in the close position by the steam pressure in chamber (C). Chamber (D) connects the main valve assembly to the pilot valve assembly. With the pilot valve in the closed position, chamber A, B, C, and D are at system pressure. The pilot valve is held closed by the pilot valve spring and the steam pressure in chamber (E). When the solenoid is actuated the plunger head moves downward striking the pilot operating lever. The operating lever opens the pilot valve disc, thus allowing steam from chamber (D) to vent through port (F). The steam is vented from chamber (D) faster than it is supplied to chamber (C) via the clearance between the valve disc and the disc guide. The resultant unbalance of pressure in chamber (B) and (C) produce a force that moves the main valve disc downwards and allows steam to escape. If the actuating signal resets, the solenoid plunger retracts and the pilot valve reseats. The pressure in chamber (C) increases causing the relief valve to reclose.

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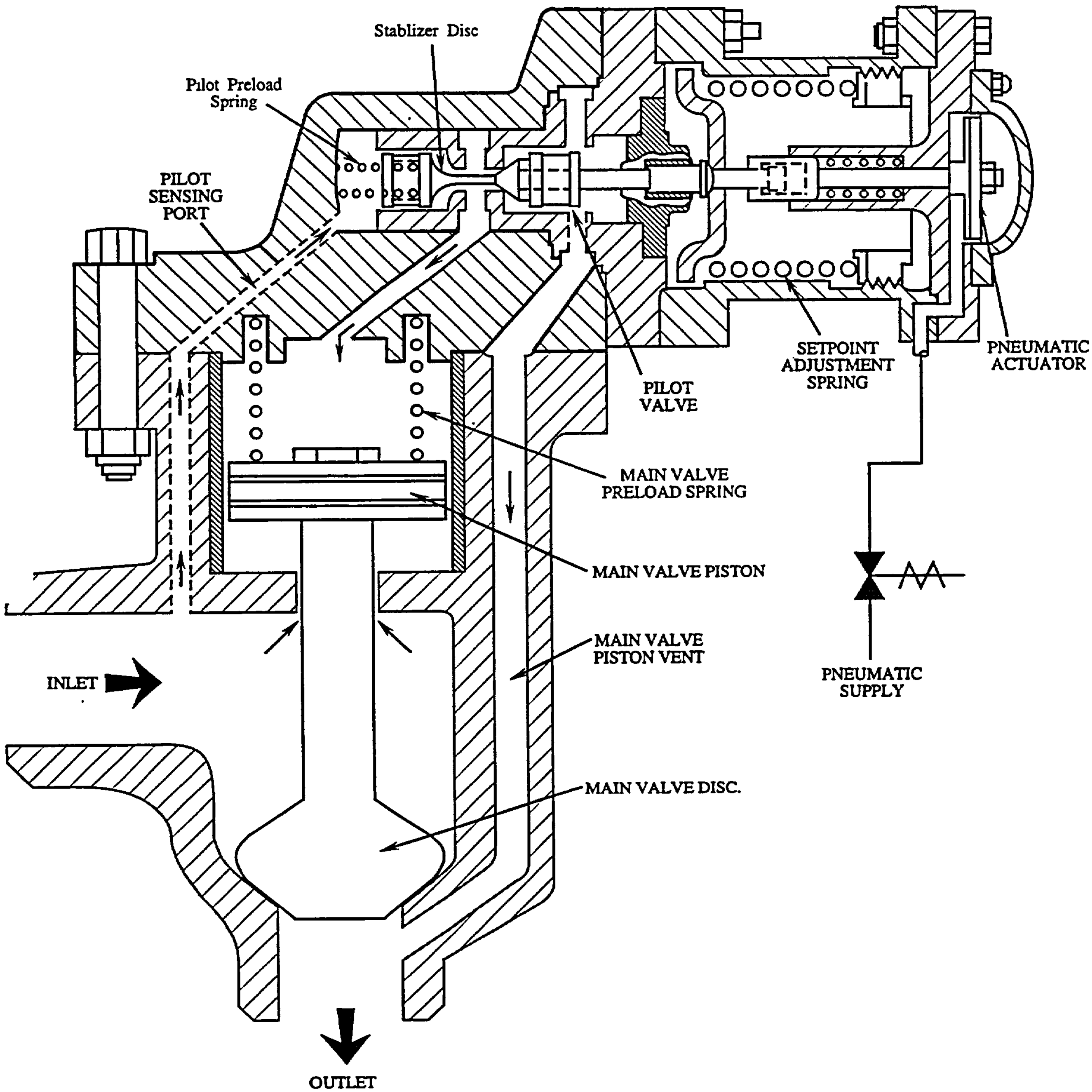

Figure 6.8-1 Two Stage Target Rock SRV (Closed)

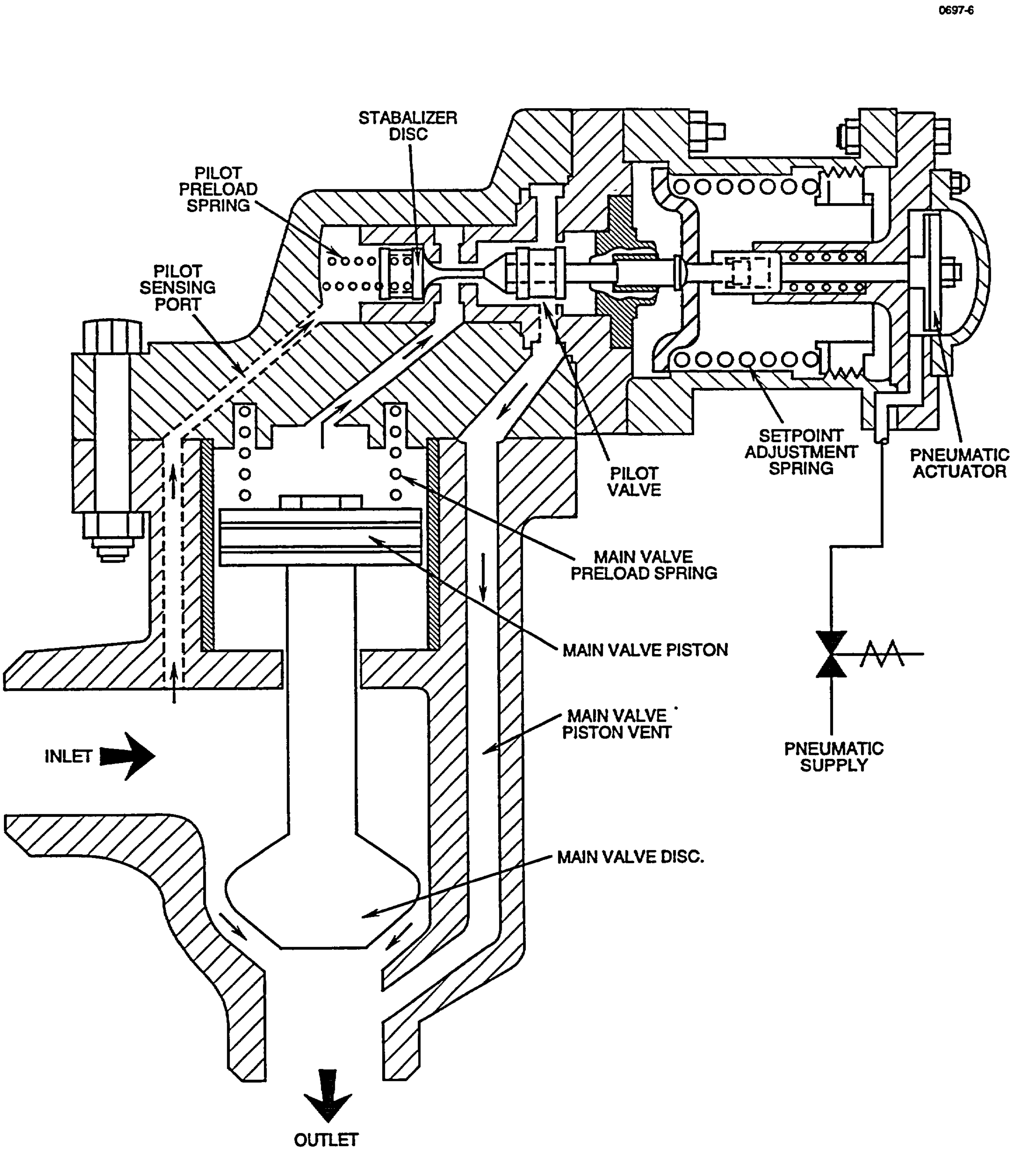

Figure 6.8-2 Two Stage Target Rock SRV (Open)

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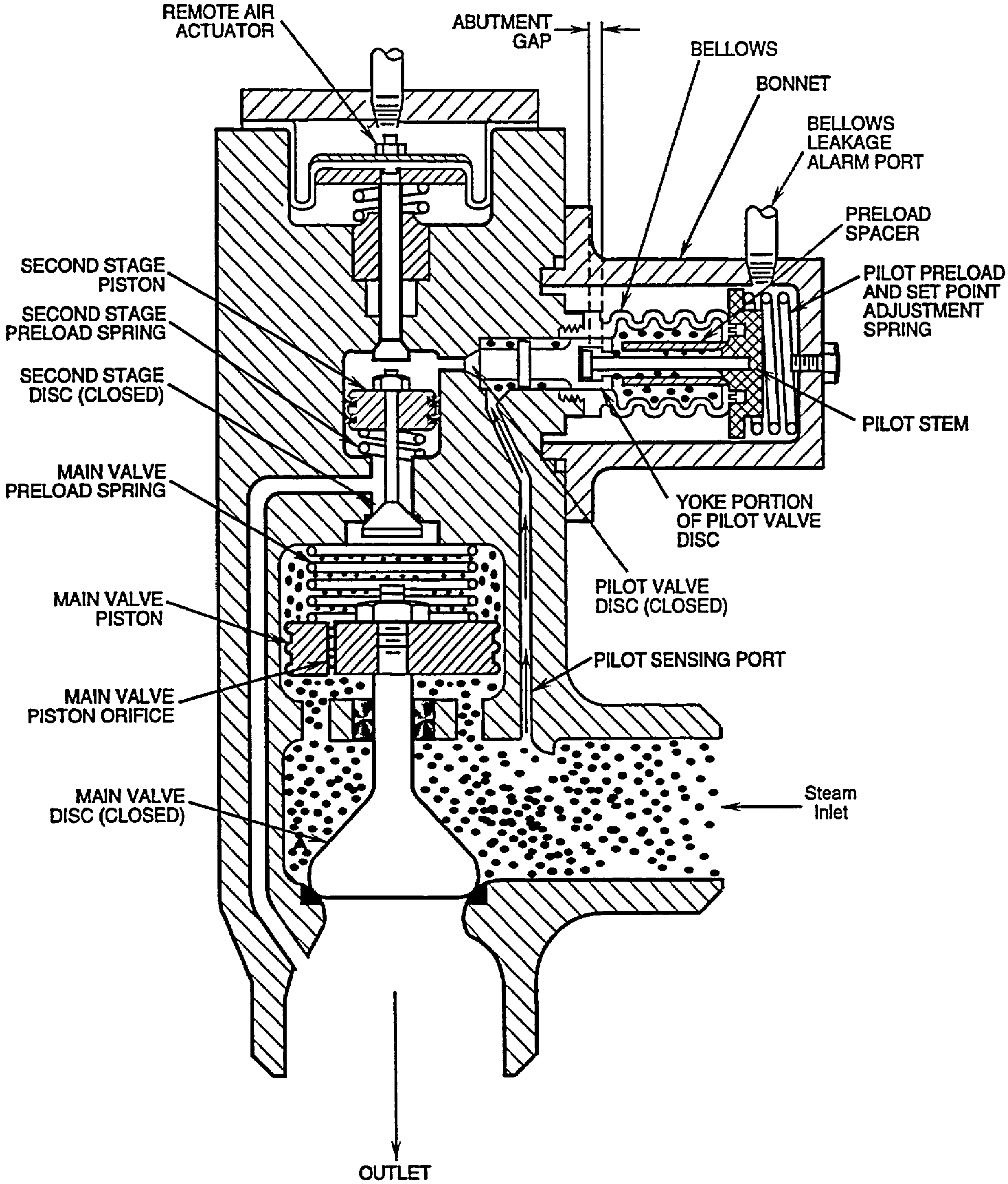

Figure 6.8-3 Three Stage Target Rock SRV (Closed)

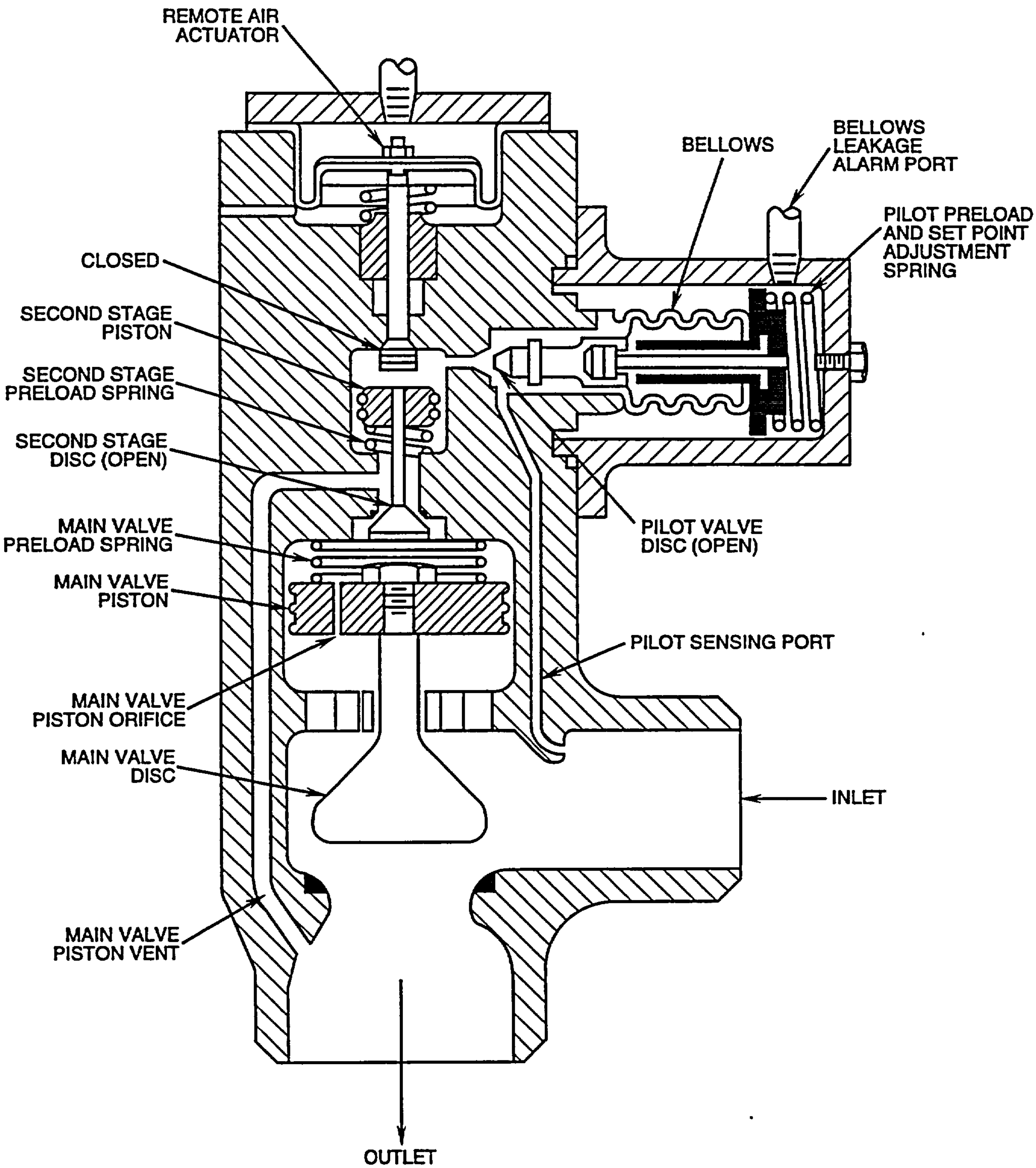

Figure 6.8-4 Three Stage Target Rock SRV (Safety Actuated)

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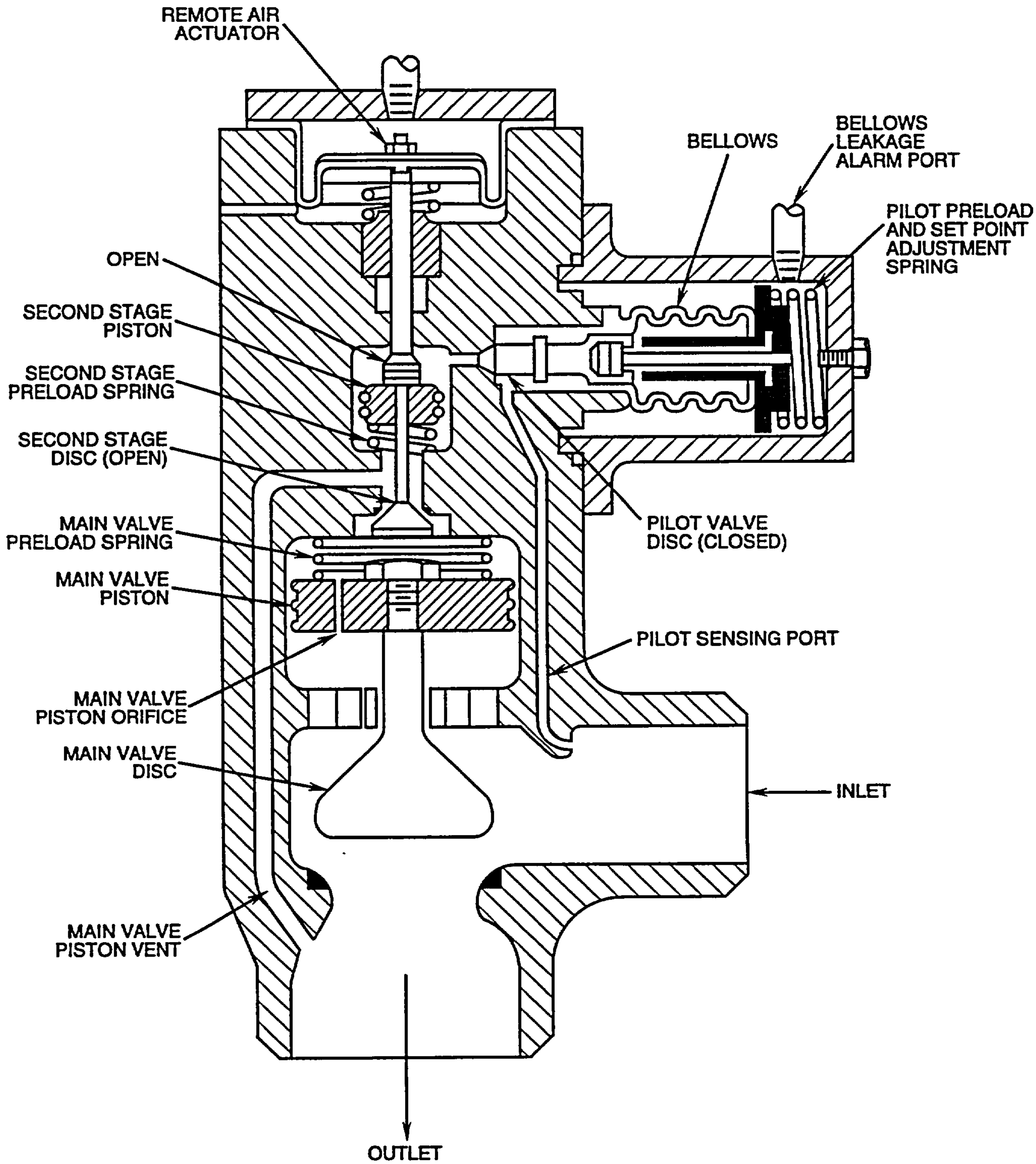

Figure 6.8-5 Three Stage Target Rock SRV (External Actuation)

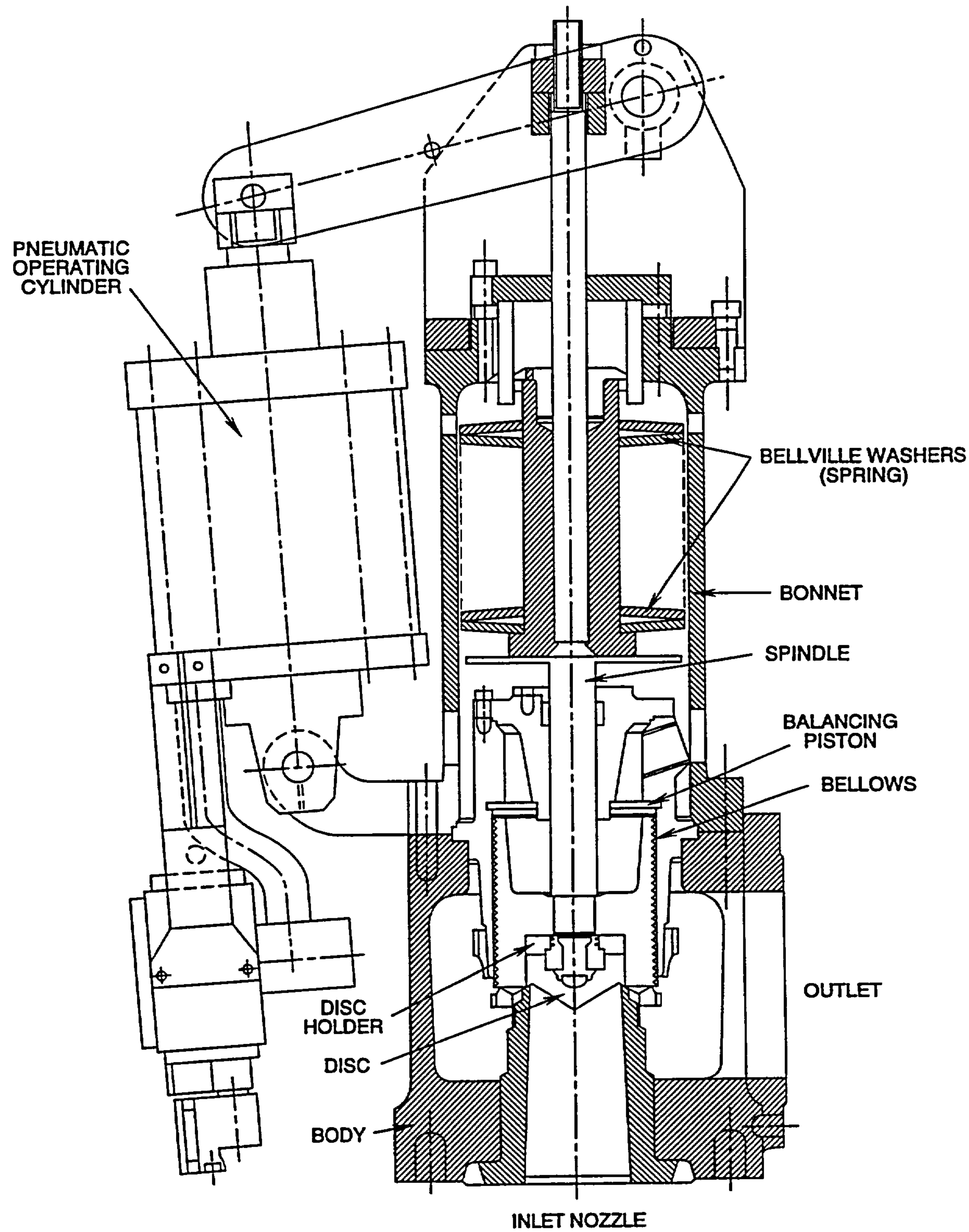

Figure 6.8-6 Dickers SRV

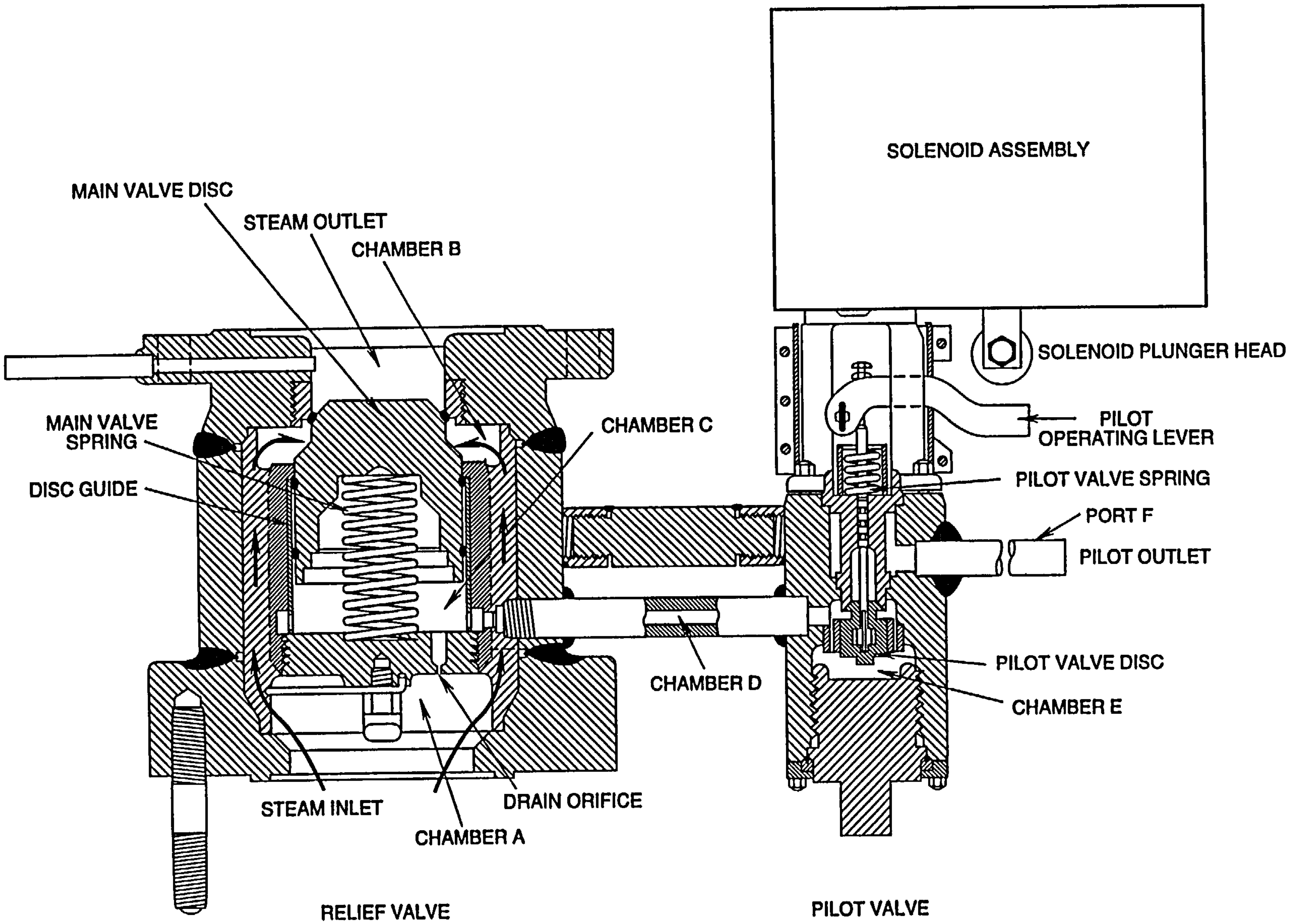

Figure 6.8-7 Electromatic Relief Valve

Boiling Water Reactor
GE BWR/4
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Chapter 7.0

Plant Events

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7.1 BROWN'S FERRY FIRE LOG SUMMARY

Learning Objectives:

1. List and explain the items learned from the event.

2. List the three major fire fighting systems.

3. List the pumps capable of supplying water to the reactor vessel at normal operating pressure.

7.1.1 Introduction

The Brown's Ferry Nuclear Plant consists of three BWR/4 units, each designed to produce approximately 1100 megawatts of electrical power. Units 1 and 2 were both operating at the time of the fire. Unit 3 was still under construction. At approximately 1235pm, March 22, 1975, a fire was reported in the unit 1 reactor building. The immediate cause of the fire, unknown to the operators, was the ignition of the polyurethane foam which was being used to seal air leaks in the cable penetrations between the unit 1 reactor building and a cable spreading room located beneath the control room of units 1 and 2 (Figure 2.4-1). The material ignited when a candle flame, which was being used to test the penetrations for leakage, was drawn into the foam by air flow through the leaking penetration.

Following ignition of the polyurethane foam, the fire propagated through the penetration in the wall between the cable spreading room and the unit 1 reactor building. In the cable spreading room, the extent of burning was limited and the fire was controlled by a combination of the installed carbon dioxide extinguishing system and manual fire fighting efforts. Damage to the cables in this area was limited to about 5 feet next to the penetration where the fire started. The major damage occurred in the unit 1 reactor building adjacent to the cable spreading room, in an area roughly 40 feet by 20 feet, where there is a high concentration of electrical cables.

Approximately 1600 cables were damaged. There was very little other equipment in the fire area and the only damage, other than cables, cable trays, and conduits, was the melting of a solder joint on an air line and some spalling of concrete. The electrical cables shorted together and grounded to their supporting trays or conduits after the insulation burned off. Sufficient equipment remained operational throughout the event to shutdown both reactors and maintain the reactor cores in a cooled and safe condition, even though all of the emergency core cooling systems for unit 1 where inoperable. No release of radioactive material above the levels associated with normal plant operation resulted from the event.

7.1.2 Fire

Starting about 5 minutes after the control room was first notified of the fire, alarms were received on the unit 1 control panel which contains the controls and instrumentation for much of the ECCSs. Comparison between the indications (alarms) revealed discrepancies. For example, one panel indicated all the ECCS pumps were operating, whereas another indicated normal reactor parameters with no need for such emergency operation. Intermittent and apparently spurious alarms continued at a lesser rate. Reactor power had by this time decreased from 1100 MWe to almost 700 MWe due to a decrease in recirculating pump speed from a cause unknown to the operator. At 1251 the recirculation pumps tripped and the reactor was manually scrammed. The rod position information system was operating at the time and all rods were verified to be fully inserted. Unit 2 was manually scrammed a short time later due to similar indication and control problems.

The operators still did not know the extent of the fire and its location was only generally defined. The operators did verify that there was no immediate threat to the safety of the reactors, but that the fire was affecting the emergency core cooling systems.

Normal cooldown was interrupted when the main steam isolation valves closed on unit 1 less than fifteen minutes after scram and on unit 2 less than ten minutes after scram. Although isolated from the main condenser, the plants could remain in hot standby by using the Reactor Core Isolation Cooling System (RCIC) provided for this situation.

Operation of the RCIC System was initiated on unit 2, but the system on unit 1 was disabled by the fire. The unit 1 RCIC had started earlier automatically, but was not needed then and was shutdown. When required later, it could not be restarted because of power failure to the isolation valve in the RCIC steam line which prevented it from opening and admitting reactor steam to the turbine. However, RCIC could also be driven by steam from the plant auxiliary boilers. The system is not normally connected to the boilers and this connection must be accomplished by inserting a spool piece between the RCIC turbine steam admission line and the auxiliary boilers. The spool piece had been used for startup tests and was made available for usage within an hour. With this capability in mind, the operators started an auxiliary boiler, and it was ready for use by 1330. However, the spool piece was not installed, as discussed later.

About forty minutes after scram, an operator stated that he knew that the unit 1 reactor water level could not be maintained with the running CRD pump. Also the only other available pumps could not inject water into the reactor at reactor pressures above 350 psig. After realigning the necessary valves in the feedwater lines and determining that two of the three condensate pumps and one of the three condensate booster pumps were running, the four unit 1 relief valves that could be manually operated from the control room were opened to lower reactor pressure. During blowdown, the water level dropped to about 48 inches above the top of the core and then began to rise as pressure fell below 350 psig and the condensate booster pump started injecting water into the reactor. Within two hours after scram, conditions in unit 1 had stabilized. Water level was maintained using a condensate booster pump and steam was vented to the suppression pool through the manually actuated relief valves.

Before the unit 1 relief valves were opened at 1330 to depressurize the reactor, and again after 1800 when the relief valves could not be opened, the steam generated in the reactor core caused reactor pressure to rise slowly. When pressure exceed 350 psi, the operating condensate booster pump could not inject water into the reactor. That left a single CRD pump injecting somewhat more than 100 gpm of water as pressure increased.

At high reactor pressure, automatic makeup is normally provided by the feedwater system. Backup is provided by either the steam driven HPCI or RCIC systems. On unit 1, the HPCI and RCIC were rendered inoperable by the fire shortly after their initial operation and were unavailable during the remainder of the event.

7.1.3 Source of High Pressure Makeup Water

Besides the CRD pump on unit 1, other installed sources of high pressure makeup were the CRD pump on unit 2, a shared spare CRD pump and standby liquid control (SLC) pumps. The CRD pumps, while performing normal functions associated with the control rod drive system, also provide water to the vessel at high or low pressure. One CRD pump per unit is normally in operation and the pump for unit 1 operated continuously throughout the course of the incident. In addition, the SLC pumps are each capable of providing approximately 56 gpm of water at pressures up to reactor coolant system design pressure. The SLC pumps were not required as a backup reactivity shutdown system since the control rods functioned normally.

An analysis of available evidence suggested that there was a period of up to three hours following initiation of the fire during which the SLC pumps were not available due to loss of power. However, the power for at least one pump is known to have been available at 1800 and the other was readily available or could have been made available, if needed, within 1 hour.

The operating CRD pump was part of units 1 and 2 system which consisted of three CRD pumps. One pump was normally operating in each unit and the third pump was available for use in either unit. Also, subsequent examination of the actual piping configuration confirmed that it was also possible to align the unit 2 pump to provide water to unit 1. Means also existed to increase the output of a CRD pump by valving in the pump test bypass line. It was estimated that by opening that single valve it would have been possible to provided approximately 225 gpm and maintain the core covered throughout the course of the incident. No other systems would have been required to provide water to the reactor vessel and depressurization would not have been necessary. The 225 gpm flow could have been increased to 300 gpm by placing an additional CRD pump in service.

An additional source of high pressure water, mentioned previously as being unavailable due to fire damage, was the unit 1 RCIC system. The RCIC pump would have been capable of providing sufficient makeup flow (600 gpm) to the reactor vessel through the entire course of the incident if the decision had been to make it available. It appears that this system could have been in service within an hour after making the decision. The source of steam for the RCIC system would have been an auxiliary boiler which was used for testing the RCIC prior to plant operation. Two procedures were necessary to provide the steam path. First, the auxiliary boiler must be put into operation. Full steam pressure from this source can be obtained in less than one hour. The operators actually put the auxiliary boiler into operation by 1330, and it was available during the time the relief valves could not be opened. The second procedure installs a spool piece into the steam flow path from an auxiliary boiler to the RCIC turbine. This could have been accomplished in less than one hour. The operation of the RCIC would then have been possible from the backup control panel. However, the system was not actuated. Instead, actions to restore relief valve operability was accomplished in approximately 3-1/2 hours following which the reactor vessel pressure was once again reduced to below the shutoff head of the condensate booster pump and it was not used to provide makeup.

7.1.4 Possible Operator Actions

There were other courses of action which might have been taken by the operator in the event that remote-manual operation of the relief valves was lost. Reactor pressure could have been allowed to increase to the setpoints of the relief valves with subsequent steam relief to the suppression pool. Adequate makeup was available from the CRD pump. Considerable time became available for other operator actions as decay heat subsided: two hours at 1330; at least 8 hours at 1800 p.m. The alternative sources of high pressure makeup water was available even if control air to the relief valves could not be reestablished.

Calculations, however, indicate that after 1900 no augmentation of CRD pump flow was necessary to maintain the plant in a safe condition. This was due to the availability of a depressurization and heat removal path via the main steam line drain valves to the condenser. Both of these valves were electrically inoperable as a result of fire damage. The operators, however, decided to return draining capability to the main steam lines and this was achieved at approximately 1900.

It was calculated that the quantity of steam being removed from the pressure vessel through main steam drain lines was great enough that reactor pressure would have leveled prior to reaching the relief valves setpoints. That lower equilibrium pressure condition would have reduced the head on the operating CRD pump such that the pump would have provide sufficient makeup flow to the core covered throughout the remainder of the incident.

7.1.5 Enforcement Items

The following apparent items of noncompliance were identified during the investigation:

7.1.5.1 Failure to Comply with 10CFR 50.59

10 CFR 50.59, requires, in part, that records be maintained of changes to the facility to the extent that such changes constitute changes to the facility as described in the Safety Analysis Report. It further requires that these records shall include a written safety evaluation which provides the bases for the determination that the change does not involve an unreviewed safety question. The Browns Ferry FSAR Section 5.3.3.5 specifies, in part, that all electrical penetrations are sealed with sealant around conductors.

Contrary to this requirement, a safety evaluation was not made of the "change to the facility as described in the Safety Analysis Report" which was constituted by operation of the reactor with containment penetrations unsealed while concurrently sealing and testing the penetrations. This infraction had the potential for causing or contributing to an occurrence related to health and safety.

7.1.5.2 Failure To Comply With Technical Specifications

The Technical Specifications, Sections 6.3.A and 6.3.B state, in part:

1. Detailed written procedures, including applicable check-off lists covering items listed below shall be prepared, approved and adhered to . . . .'
   a. Emergency conditions involving potential or actual release of radioactivity. . . .'
   b. Preventive or corrective maintenance operations which could have an effect on the safety of the reactor.
   c. Surveillance and testing requirements . . . .'
2. Written procedures pertaining to those items listed above shall be reviewed by PORC and approved by the plant superintendent prior to implementation. . . Such changes shall be documented and subsequently reviewed by PORC and approved by the plant superintendent." Contrary to these Technical Specifications requirements, the following problems were identified:
   a. The leak testing, sealing and inspection of the penetrations were being accomplished; but detailed written procedures approved by the plant superintendent and reviewed by PORC had not been developed for the control of this work.
   b. Persons discovering the fires on March 20 and March 22, 1975, did not adhere to the provisions of the Emergency Procedure in that they did not initiate the fire alarm.
   c. The Browns Ferry Emergency Procedure was not adhered to in that the Shift Engineer did not delegate on scene responsibility for fire fighting to an assistant shift engineer when he departed the fire area.

There were also problems identified with Technical Specifications compliance with plant procedures. For example, the Browns Ferry Standard Practices Manuah specified, in part (in Standard Practice BFS3) that: "Plant fire protection systems shall be fully operational at all times. Removal of a plant fire protection system from service for any reason other than as required in a test procedure requires the approval of the plant superintendent. Removal of a system from service for more than seven days requires a review of PORC."

Contrary to these requirements, the fire protection system for the cable spreading room was not fully operational in that metal plates had been installed under the glass in the manual stations during the construction of the plant and had not been removed. The approval of the installation of the plates had not been documented prior to or subsequent to the issuance of the operating license and the installation had not been reviewed by PORC. Additionally, the CO_2 manual-automatic initiation system had been electrically disabled by the construction workers without documented approval of the Plant Superintendent.

This infraction had the potential for causing or contributing to an occurrence related to safety.

7.1.5.3 Failure to Comply with Appendix B to 10 CFR 50

Criterion XVI of Appendix B to 10 CFR 50 and the related commitments in the FSAR, Appendix D.4, "Operational Quality Assurance Program Plan," Section D.4.2.4.7 specifies, in part, that measures be established to assure that conditions adverse to quality are promptly identified and corrected; that measures assure that causes of conditions be determined and action taken to preclude repetition; and that the corrective actions are documented and reported to appropriate levels of management.

Contrary to these requirements, during the penetration sealing operations, the conditions adverse to quality were not promptly identified and corrected; the causes of conditions were not determined and actions taken to preclude repetition; and the required documentation was not supplied in the two instances that fires were reported to management. This infraction had the potential for causing or contributing to an occurrence related to safety.

Criterion X of Appendix B to 10 CFR 50, requires, in part, that a program for inspection of activities affecting quality be established to verify conformance with documented instructions, procedures, and drawings; and that persons assigned the responsibilities for such inspections shall be independent of individuals directly responsible for work performance. Related commitments are spelled out in the FSAR, Appendix D.4., Sections D.4.2.3.1 and D.4.2.1.1, respectively.

Contrary to these requirements, inspections of the sealing of cable penetrations were not conducted so as to assure conformance with drawings; and plant inspectors were involved in the work activities for which they had inspection responsibilities.

Criterion XVIII of Appendix B to 10 CFR 50, and the related commitments set forth in the FSAR, Appendix D.4 "Operational Quality Assurance Program Plan," specifies, in part, that a comprehensive system of planned audits be carried out to assure compliance with all aspects of the quality assurance program.

Contrary to these requirements, a review of the records of the audits conducted at Browns Ferry and discussions with responsible individuals indicated that no audits had been conducted of the penetration installation.

Criterion III of Appendix B to 10 CFR 50, and the related commitments set forth in the FSAR, Appendix D.2, "TVA Quality Assurance Plan for Design and Construction," Section D.2.4.3.4., specifies, in part, that certain basic design drawings, such as single line diagrams, are reviewed to determine that they meet the design bases, design criteria and other design input requirements. The FSAR, Amendment 25, "Response to AEC Question 7.5," states, in part, that cables for the Engineered Safeguards Systems are separated into two redundant divisions (Division I or Division II) such that no single credible event could damage the cables of redundant counterparts. This section further states that power cables from the 4160-Volt Shutdown Boards are installed in separate conduits. It further states that the electric circuits of one of the two loops of the Core Spray System including the pump motors and electrically operated valve, are in Division I; and the circuits of the other loop are in Division II. Additionally, it states that the electric circuits associated with pumps A and C, and their valves, of the LPCI system are in Division I; and the electrical circuits of pumps B and D, and their valves are in Division II.

Contrary to this requirement, the power cable supplying 480 Volt Shutdown Board 1B from 4KV Shutdown Board C (Division II) was routed in the same tray as the power cable supplying 480 Volt Shutdown Board 2A from 4KV Shutdown Board B (Division I).

Contrary to this requirement, RHR Pump 1C and Core Spray Pump 1C were supplied from 4KV Shutdown Board B, and their associated valves were supplied from 4KV Shutdown Board C. Shutdown Board B is in Division I and Shutdown Board C is in Division II.

7.1.6 Lessons Learned

Lessons were learned from the Browns Ferry fire and changes have been implemented at BFNP and throughout the industry related to fire protection. Some of the lessons learned are listed below:

- Improve method for air leakage test.
- Provide better fire protection systems, equipment, and establish equipment storage areas.
- Establish fire protection procedures.
- Establish fire watch procedures.
- Establish better Q/A and documentation of cable arrangement.
- Provide better power supply separation.
- Establish procedures to delineate the person in charge of control room and fire fighting.
- Establish better regulations concerning fire protection and prevention.
- Standardize fire protection equipment.

Table 7.1-1 Sequence of Events

TIME	SUMMARY
1200	Units 1 and 2 were operating at 100% power.
1235	A fire was reported in the unit 1 reactor building. Plant personnel were informed of fire location. The fire brigade began fire fighting activities.
1240	Some ECCS annunciators alarmed and all diesel generators started despite normal vessel water level, steam pressure, and drywell pressure.
1242	The RHR System aligned itself in LPCI mode with all four pumps running. All four Core Spray System pumps aligned and started. The unit operator manually secured all eight pumps but could not reset annunciators.
1244	The RHR and CS pumps restarted for no apparent reason. The unit operator was unable to stop the pumps from the control panels.
1248	The unit operator was able to stop RHR and CS pumps from the control panels. Both recirculation pumps ran back for no apparent reason causing unit power to go from 1100 MWe to 700 MWe. Electrical boards started losing power. Half of RPS was lost. Remote manual control of seven SRVs was lost. Numerous annunciators alarmed on several control panels.
1251	The unit operator started lowering recirculation pump speed. Both recirculation pumps tripped for no apparent reason at >20% loading. The unit operator manually scrammed the reactor.
1253	The unit operator confirmed that all rods were fully inserted. The unit operator tripped all but one RFP, secured extra condensate and condensate booster pumps, and manually started RCIC as a backup.
1254	The assistant shift engineer (ASE) tripped the turbine, opened the generator field breaker, and opened the motor operated disconnects. HPCI initiated automatically although the MSIVs did not close. Vessel water level increased to the normal range. Operators secured both HPCI and RCIC.
1255	120VAC unit preferred power was lost. Among other things control rod position indication and all neutron monitoring indication was lost.

Table 7.1-1 Sequence of Events

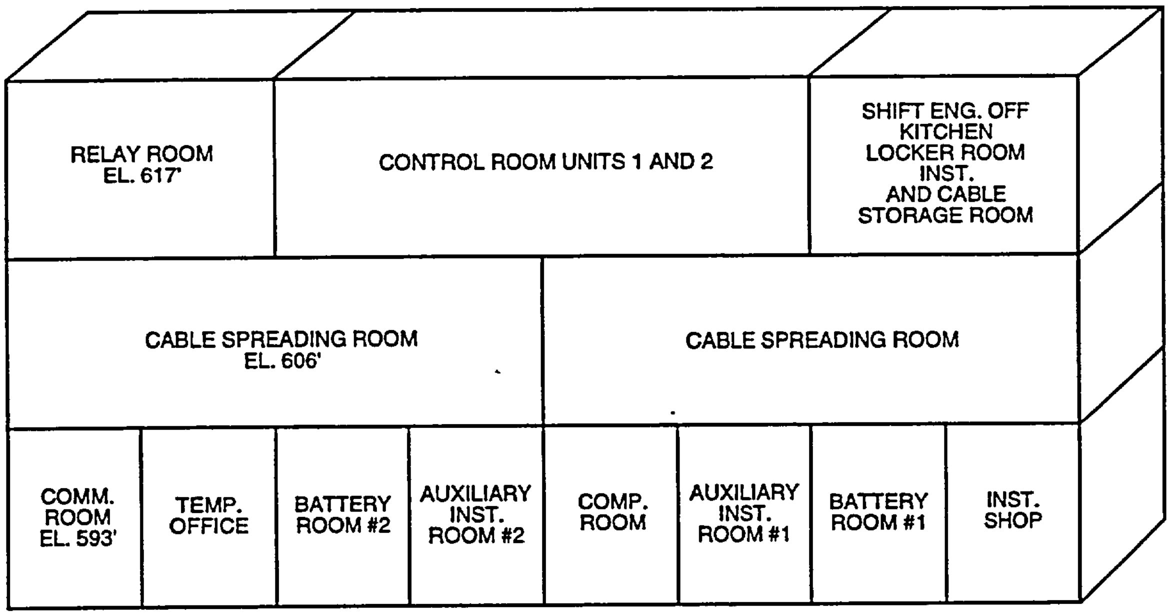
1256	Numerous electrical boards were lost: • 250Vdc Reactor MOV Board 1A • 250Vdc Reactor MOV Board 1B • 480Vac Reactor MOV Board 1A (CS, RHR, HPCI, RHRSW valves, RPS A) • 480Vac Reactor MOV Board 1B (CS RHR, RHRSW, RCIC, EECW valves, RPS B) • 480Vac Reactor MOV Board 1C(EECW, RHR valves) • 480Vac Shutdown Board 1A • 480Vac Shutdown Board 1B At this point the MSIVs closed placing the unit in isolation from the main condenser and securing steam to the RFP turbine. Also all ECCS was lost with the exception of four SRVs which could be operated from panel 9-3.
1258	Reactor pressure rapidly increased; SRVs began opening and closing to maintain pressure between 1080 and 1100 psig. An unsuccessful attempt was made to open MSIVs from the backup control center. The unit operator manually opened SRVs for which he had control and reclosed them after pressure had decreased to <850 psig. Pressure began increasing immediately.
1259	Reactor water level was decreasing due to almost constant SRVs blowdown to the torus. HPCI and RCIC were both inoperable due to the previous loss of valve controls. The only pump left with the capability to overcome a pressure above 350 psig was the CRD hydraulic pump. Torus cooling became vital due to heat added as a result of SRVs blowdown; but the RHR system was not available as a result of electrical board losses.
1300	4kV shutdown bus 2 lost power. This caused shutdown boards C and D to transfer to D/G's C and D.
1320	4kV shutdown bus 1 lost power. This caused shutdown boards A and B to transfer to D/Gs A and B.

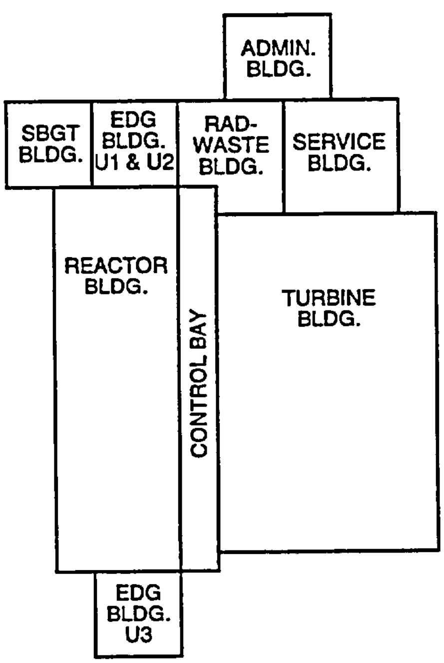
Table 7.1-1 Sequence of Events

1321	The process computer was lost.
1330	The decision was made to depressurize the reactor by SRV blowdown. The unit operator manually opened four SRVs. Reactor pressure and water level began decreasing. At this time a condensate booster pump was running and the RFP bypass valve was open.
1334	4kV shutdown bus 2 was energized from unit 2.
1345	Unit preferred power was restored from Unit 2. Reactor pressure had decreased to 350 psig allowing the condensate booster pump to start injecting. Reactor water level had dropped from a normal 201 inches above the top of the active fuel to 43 inches above the top of the active fuel. Reactor water level began to increase.
1355	Reactor water level was approaching normal but the operator lost the ability to control the RFP bypass valve.
1357	An operator was able to manually close the RFP bypass valve.
1400	The unit operator was maintaining reactor pressure at <200 psig using SRVs and vessel level about normal using the CRD hydraulic pump and a condensate booster pump. 480VAC shutdown boards A and B were restored.
1500	Attempts were made to align one RHR system for torus cooling and the other for shutdown cooling.
1600	RHR System I was aligned for torus cooling; but the decision was made not to start the RHR pumps in this condition since it was not established that the system was charged with water.
1630	480VAC reactor MOV board 1A was re-energized. This allowed placing the main turbine on the turning gear, restoring power to ECCS valves fed from that board, and energizing RPS A which restored half of the process monitoring.

Table 7.1-1 Sequence of Events

1800	SRVs previously operable from the control room became inoperable due to loss of instrument and control power to a solenoid in the air supply to a diaphragm valve in the air header to the primary containment. The drywell air compressor was started but its isolated discharge prevented air flow to the primary containment.
1900	Power was restored to the main steam line drain valves.
1945	The fire was reported out.
2008	High torus level was reached due to SRV blowdown. The assistant unit operator aligned and started the RHR drain pump to the main condenser hotwell.
2040	Drywell venting via SBGTS was started with 2.5 psig drywell pressure.
2150	A control air supply to primary containment equipment was established making four SRVs operable from the control room. The operator began lowering reactor pressure again starting from 580 psig.
2200	Reactor pressure was 340 psig and decreasing slowly.
2250	Secondary containment was established. Reactor pressure was 200 psig with vessel water level being controlled at 36" by a condensate booster pump.
0000	The need existed to flush RHR System II prior to placing it in shutdown cooling. A temporary flushing procedure had to be developed since the existing procedure could not be used.
0100	Two source range monitors were placed in temporary service on the reactor side of the fire. This established the capability to monitor the core with 10 cps indicated on each SRM.
0130	Torus cooling was initiated using RHR System I
0245	Restoration of equipment had progressed to the point that core spray pumps A and C were operable from the control room.
0410	Shutdown cooling was established using RHR System II.
0930	The unit reached the cold, shutdown condition. Drywell temperature was 120°F. Torus temperature was 130°F and level +4".





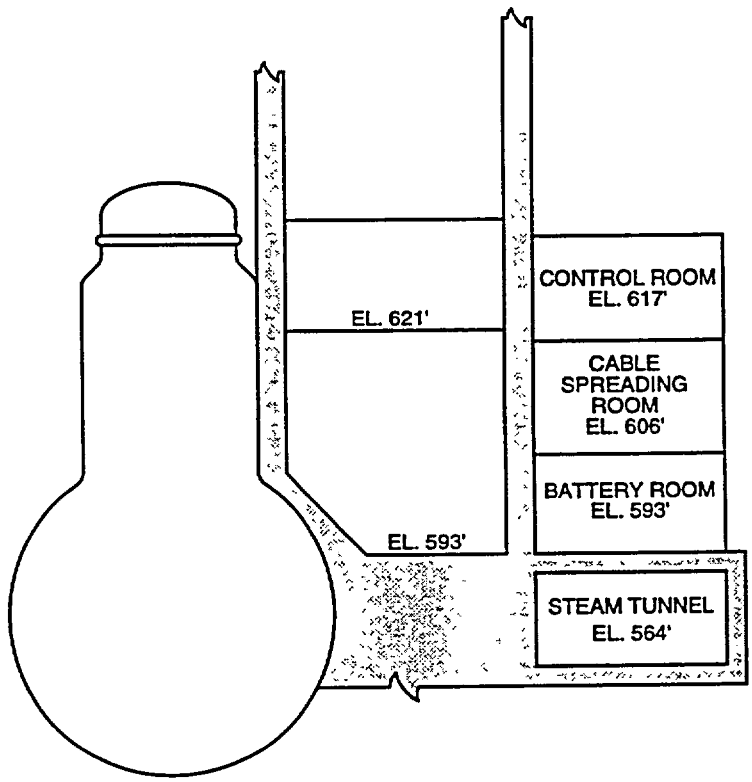
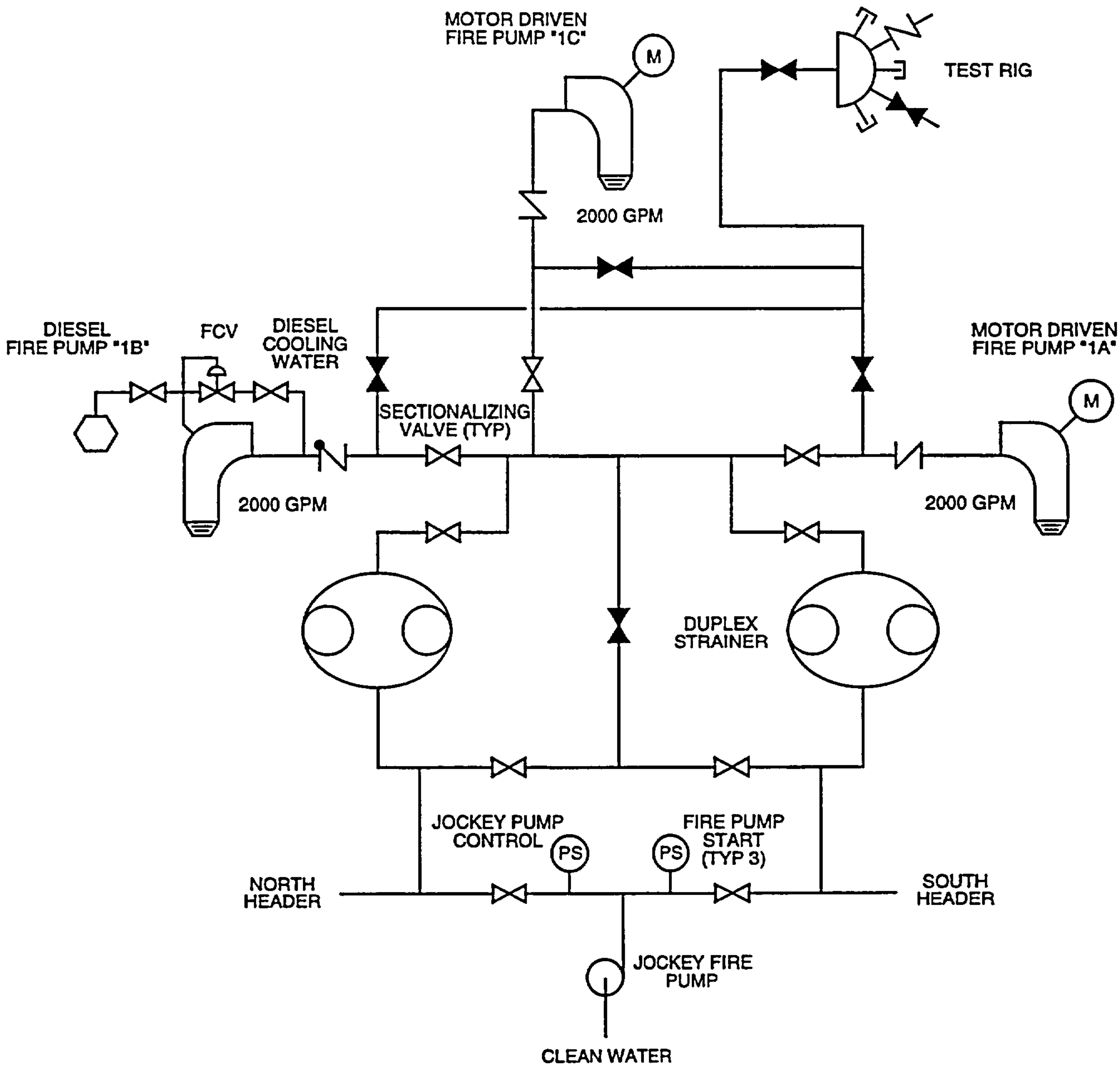


Figure 7.1-1 BFNP Control Bay Arrangement



TYPICAL START SEQUENCE

JOCKEY PUMP—100 PSIG

FIRE PUMP 1A — 80 PSIG

FIRE PUMP 1B — 75 PSIG

FIRE PUMP 1C — 68 PSIG

Figure 7.1-2 Fire Water Header

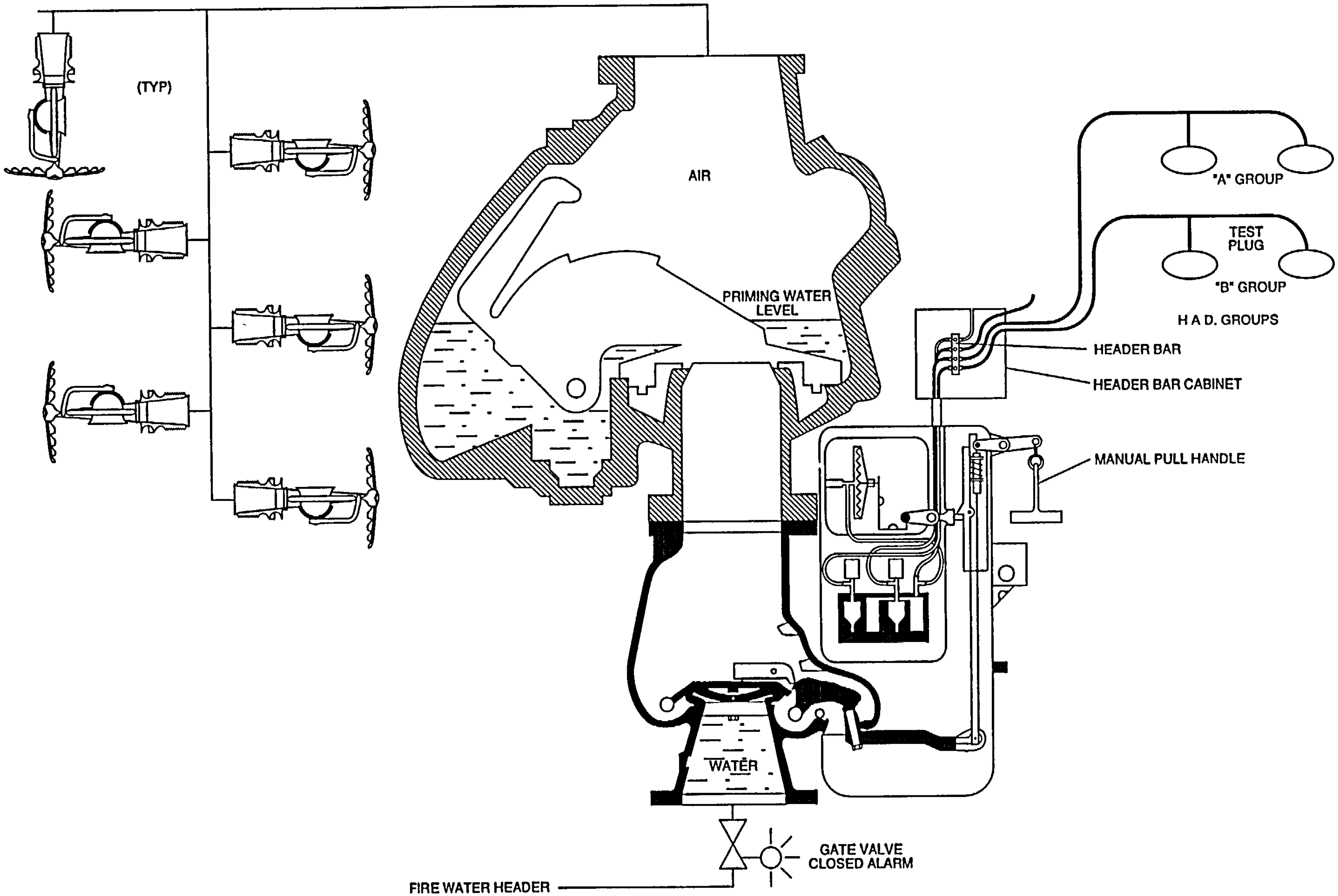


Figure 7.1-3 Preaction Sprinkler System

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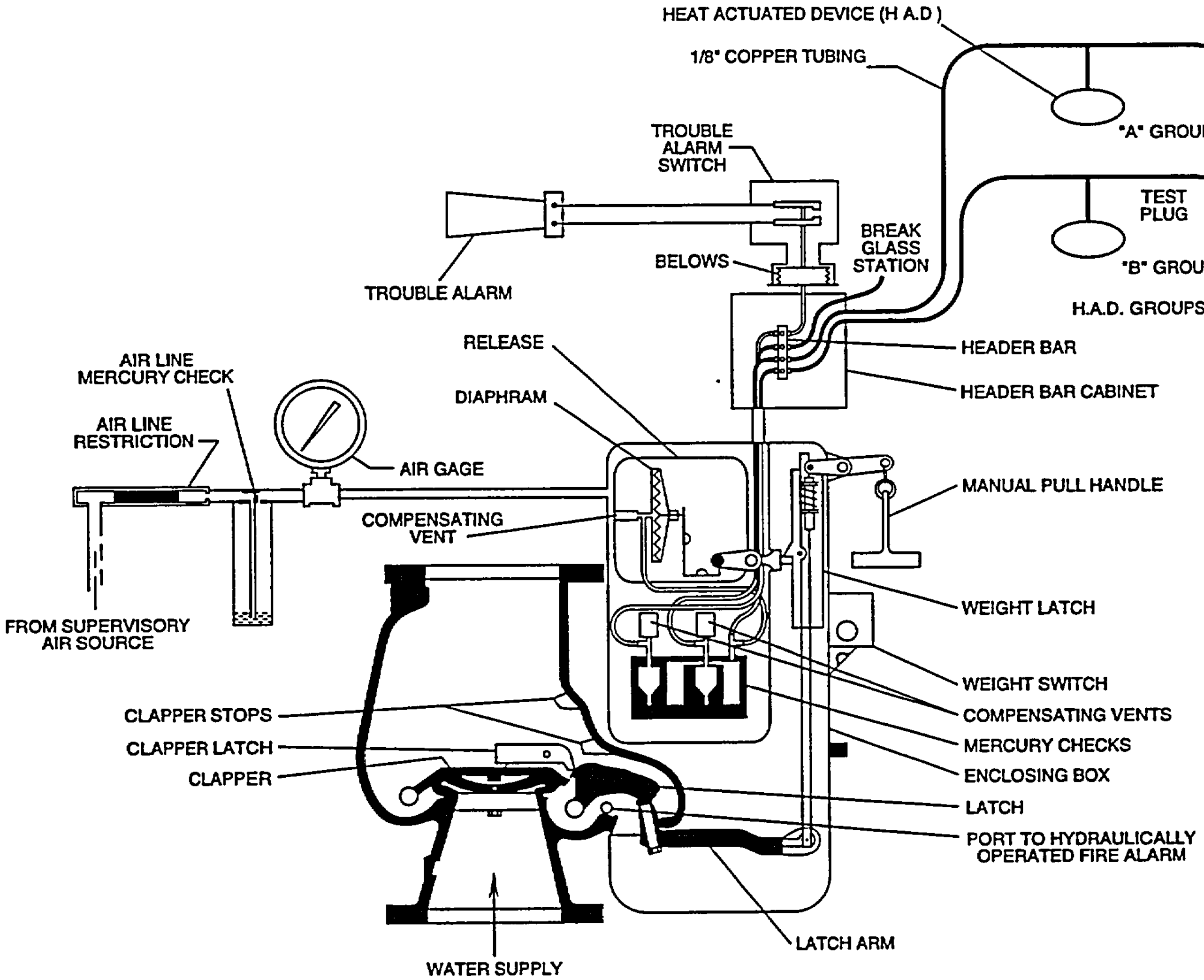
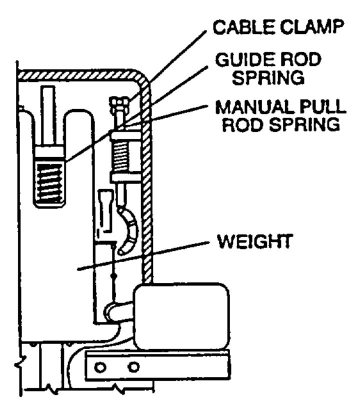
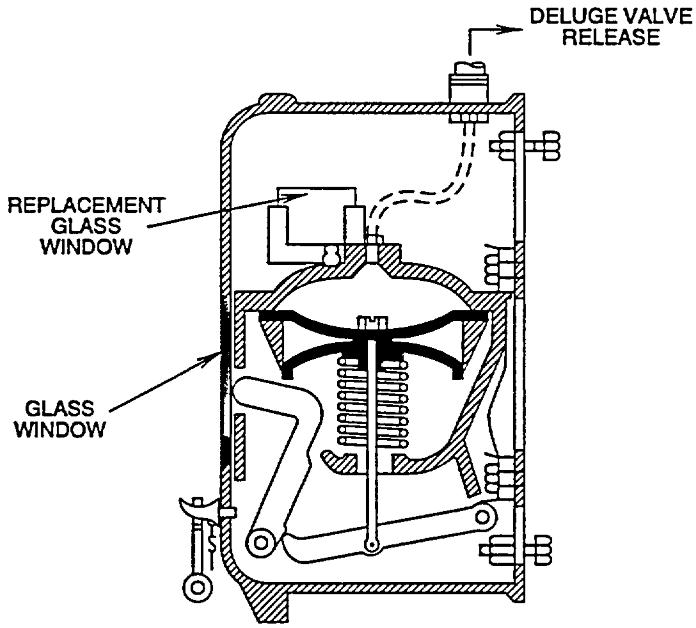


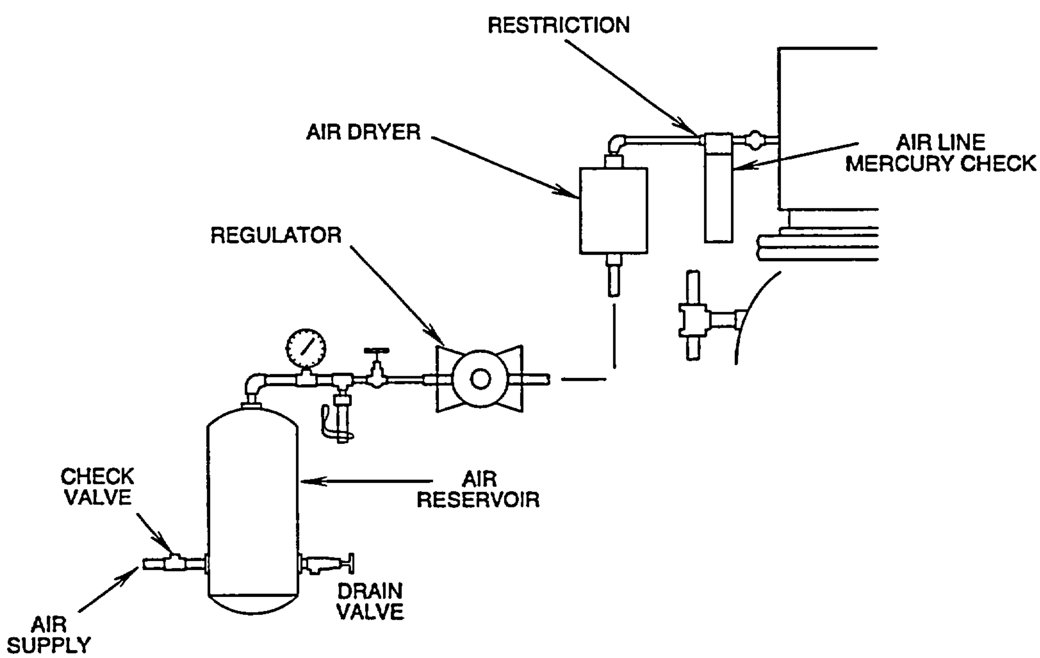


SECTION THRU WEIGHT SWITCH

Figure 7.1-4 Protection System Deluge Valve



BREAK GLASS STATION



SUPERVISORY AIR SUPPLY

Figure 7.1-5

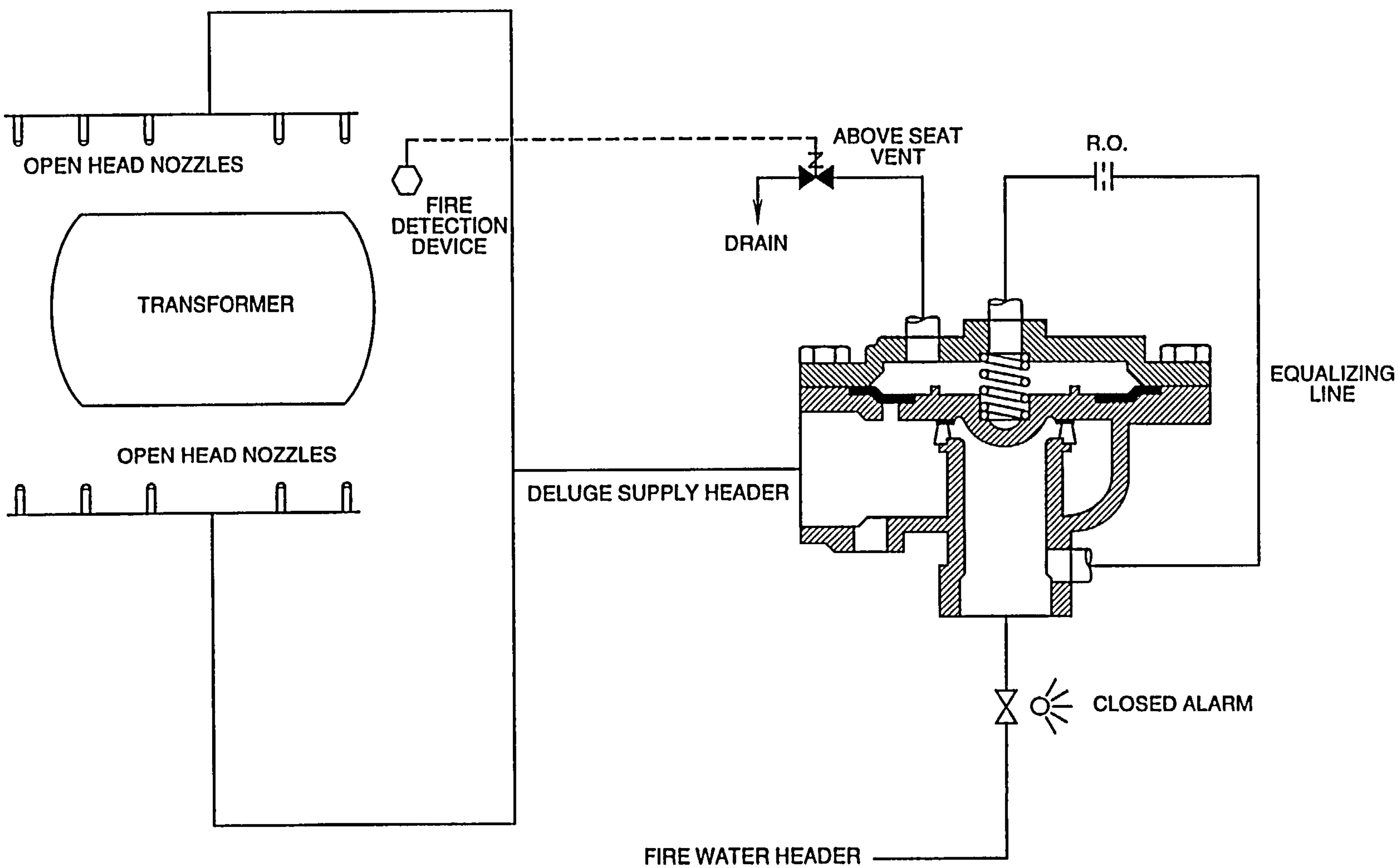


Figure 7.1-6 Deluge System

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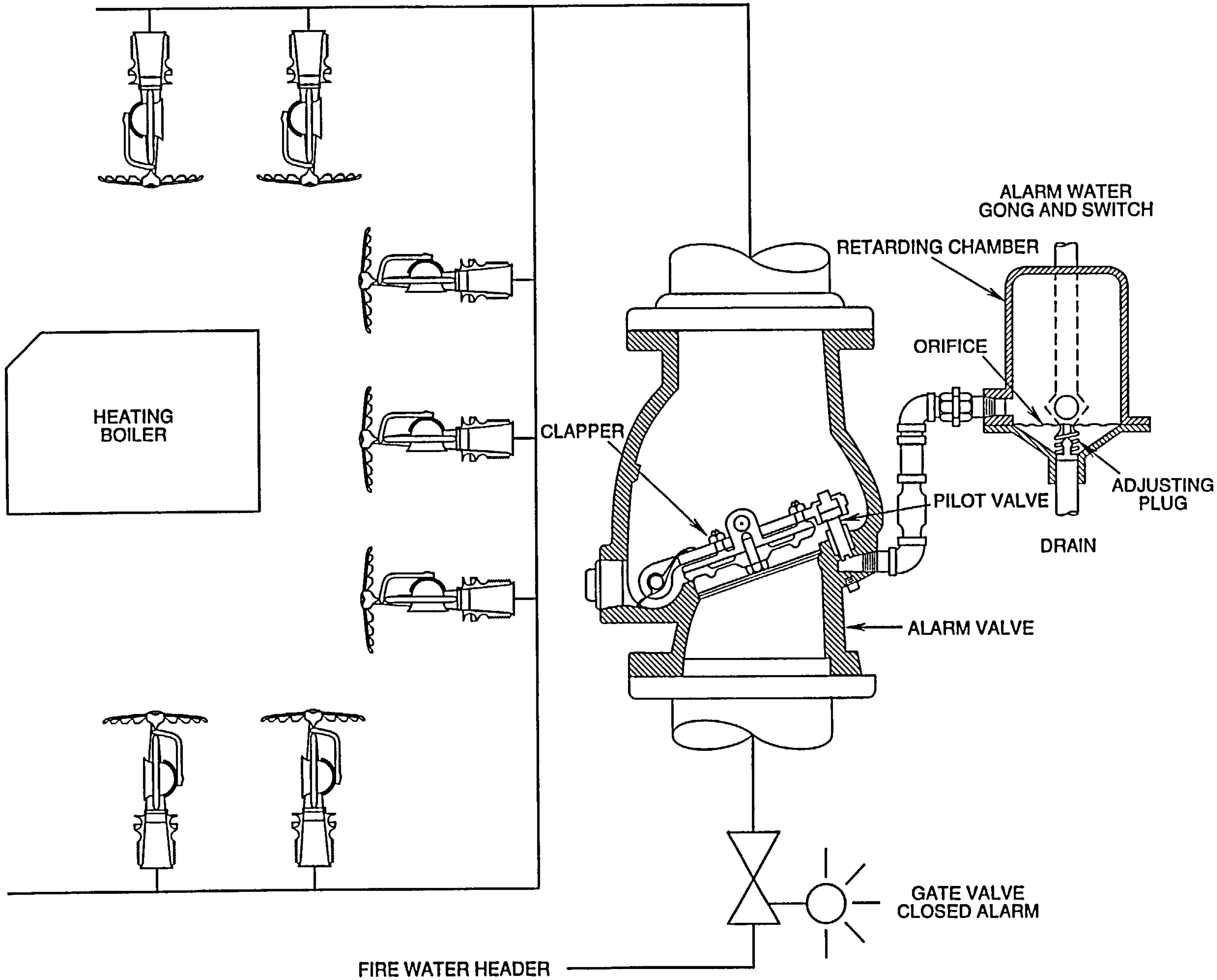

Figure 7.1-7 Wet-Pipe Sprinkler System

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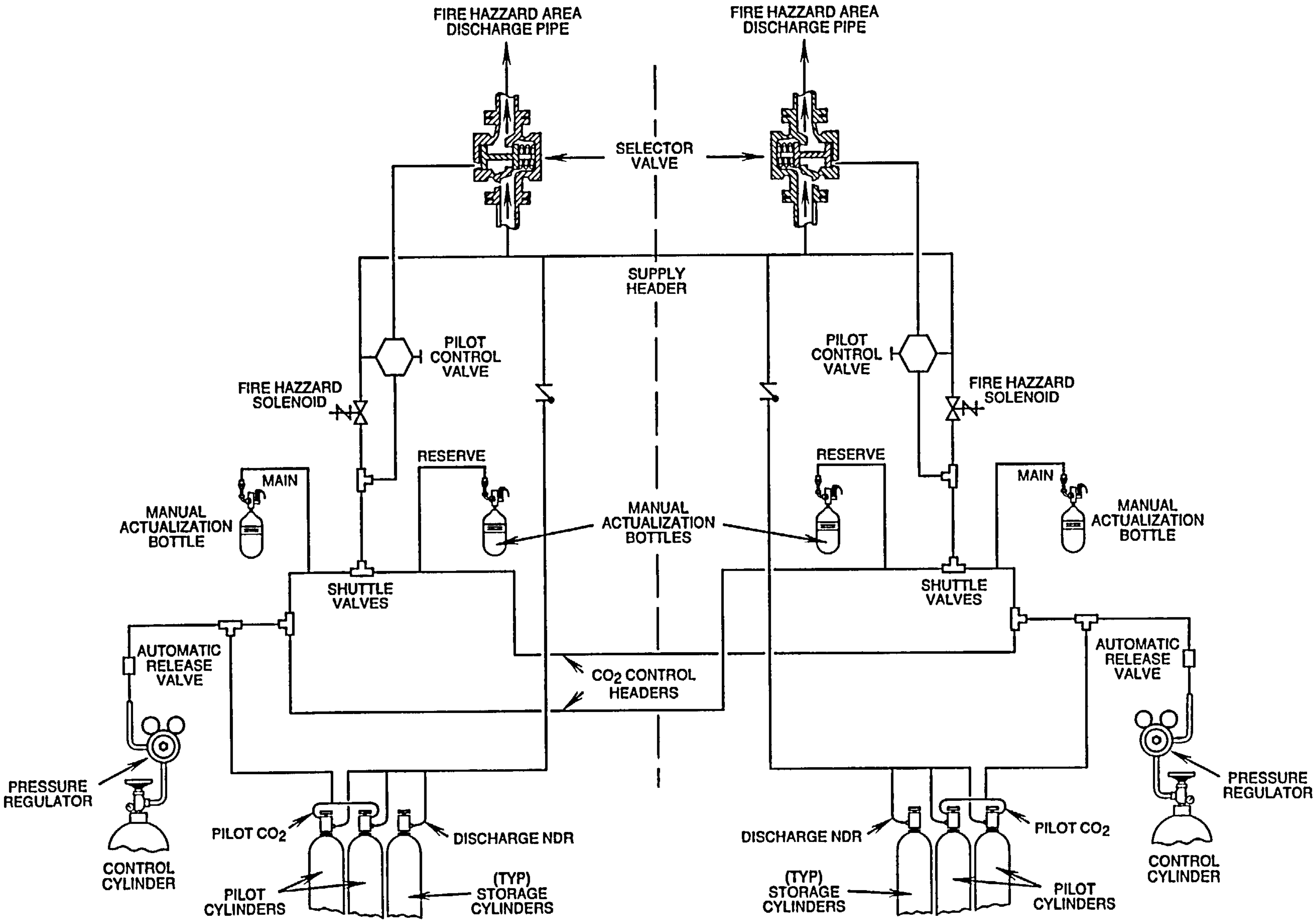

Figure 7.1-8 High Pressure Carbon Dioxide System

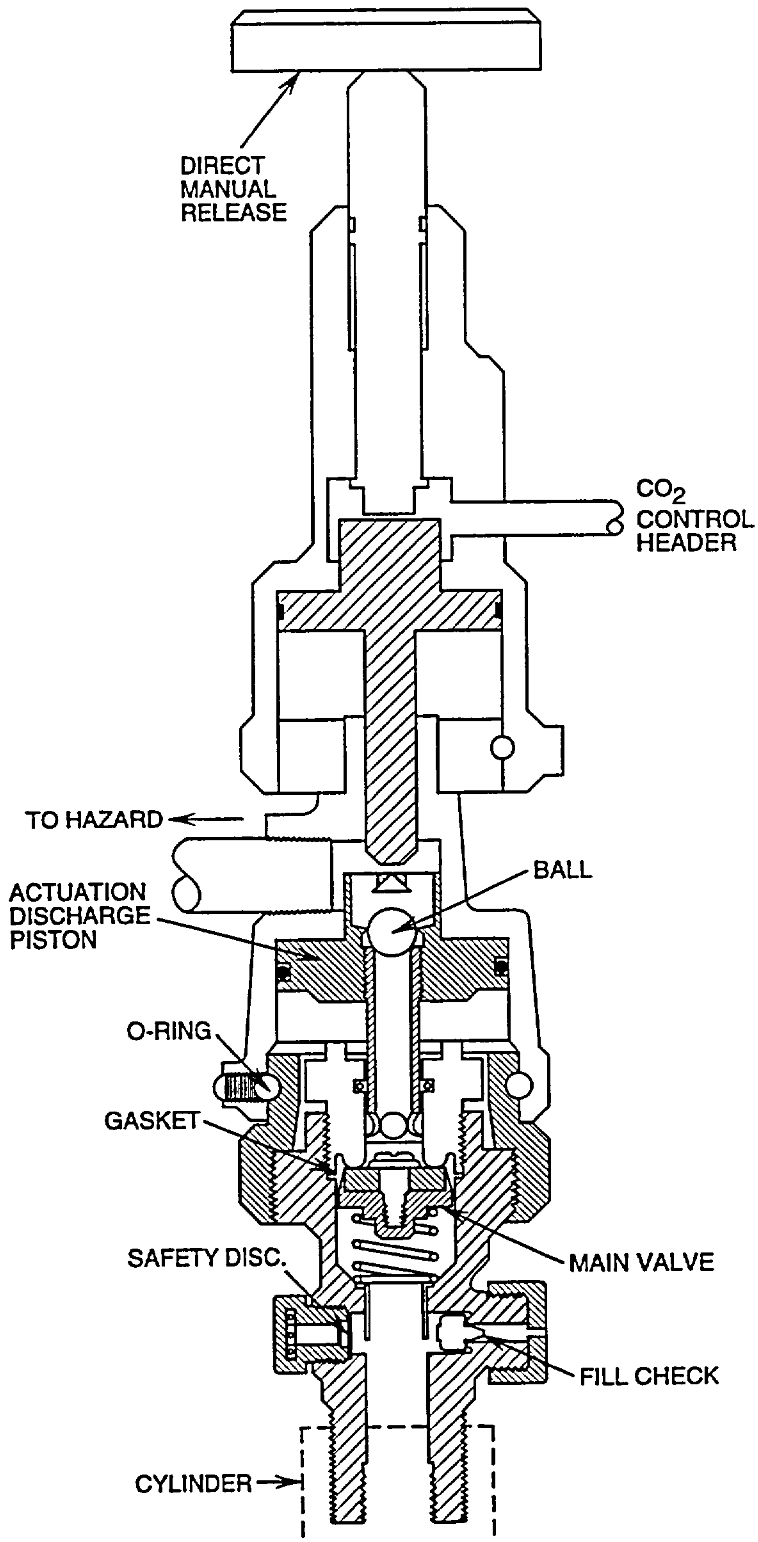

Figure 7.1-9 Pilot Control Cylinder Discharge Head

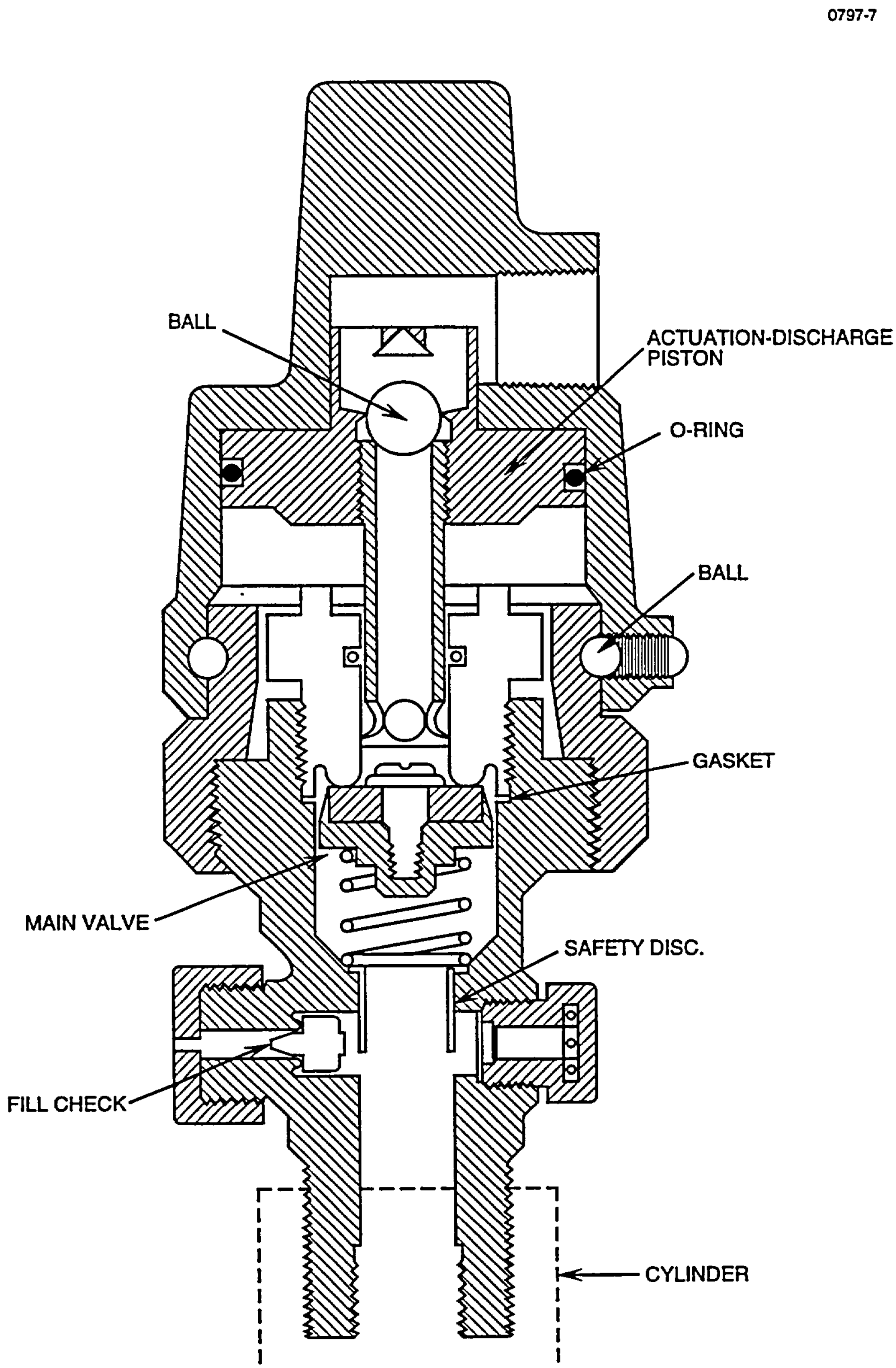

Figure 7.1-10 Actuation/Discharge Head Assembly

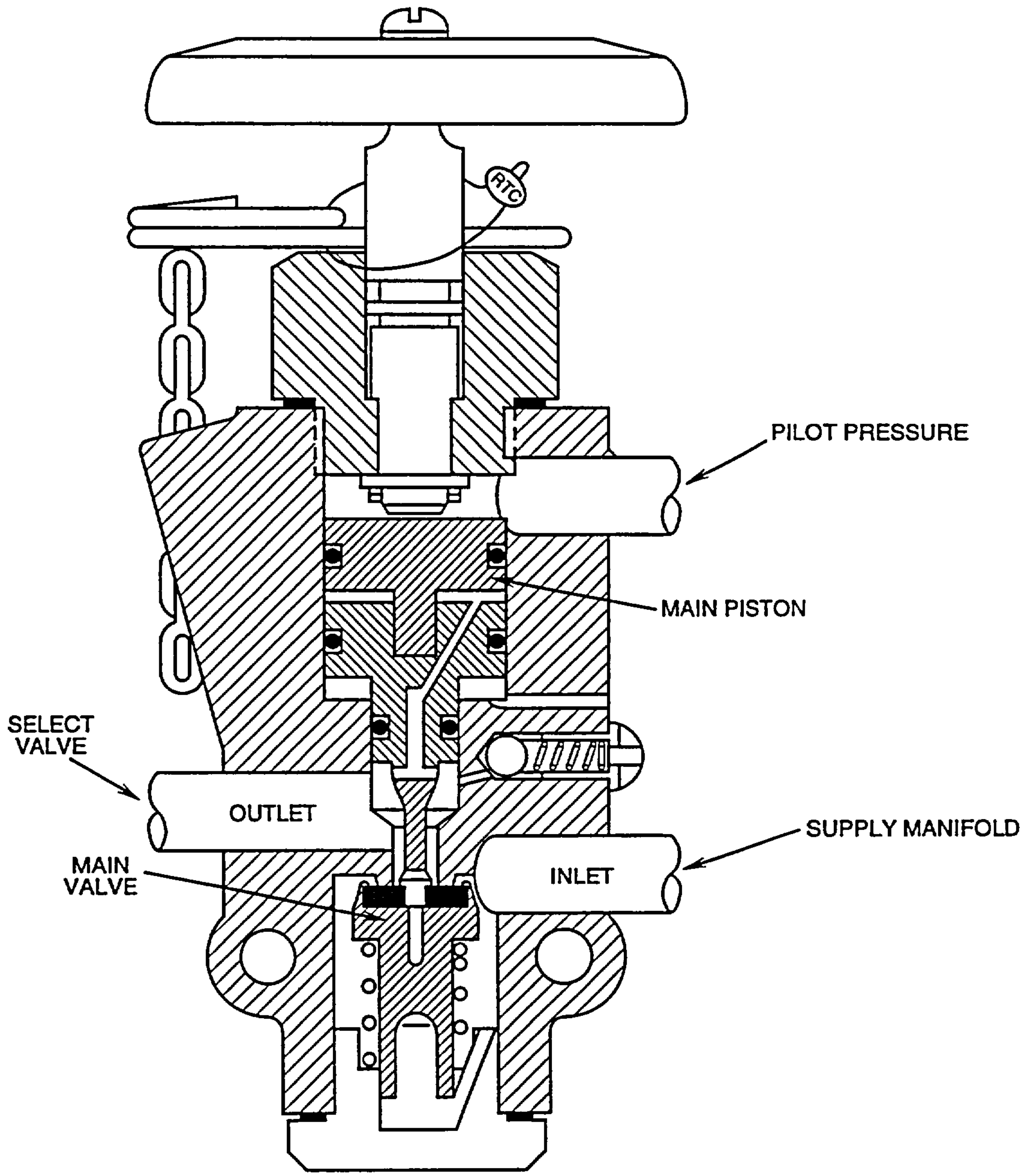

Figure 7.1-11 Pilot Control Valve

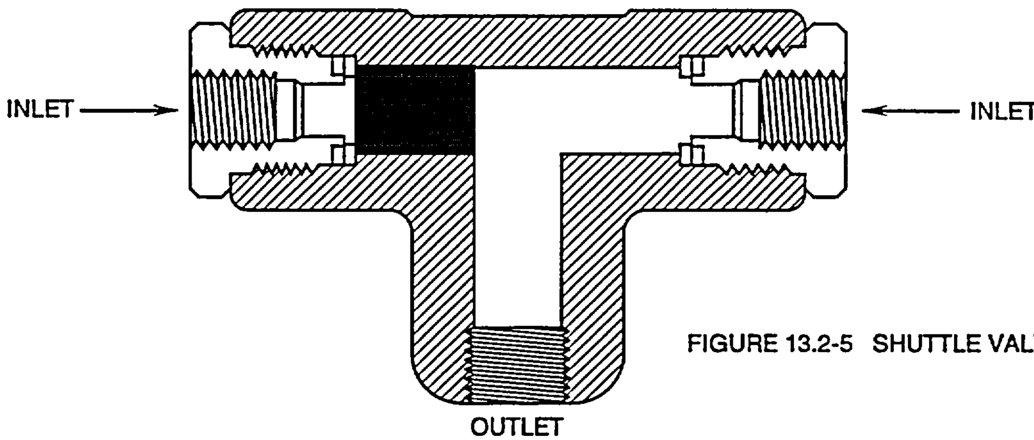

FIGURE 13.2-5 SHUTTLE VALVE

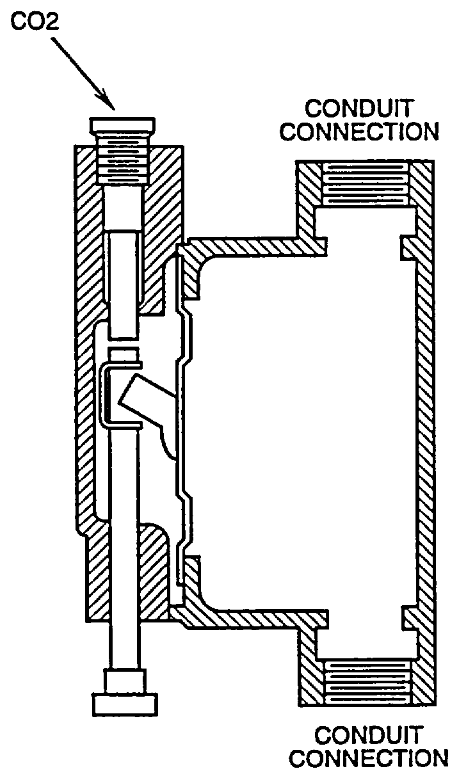

Figure 7.1-12 Cardox Pressure Switch

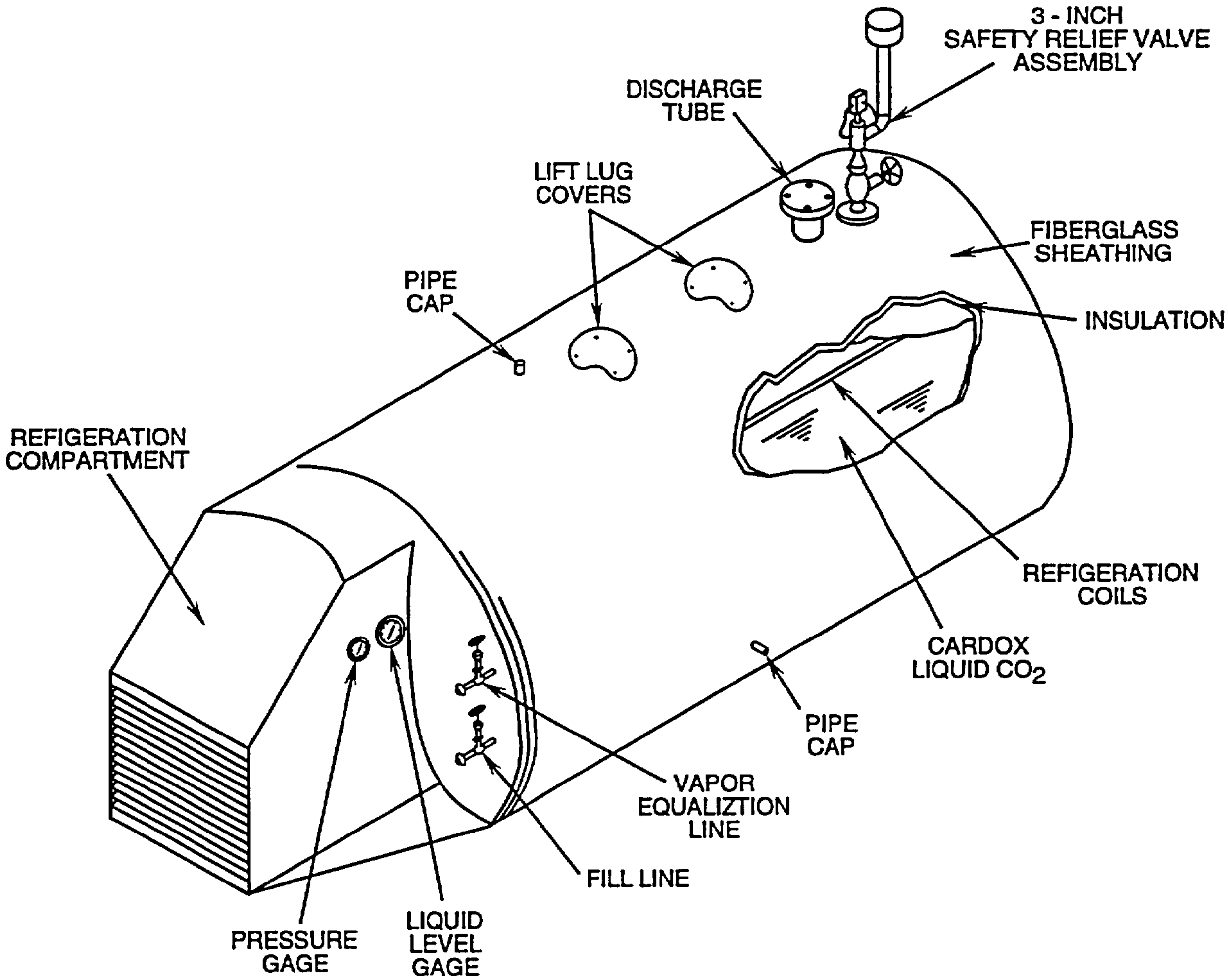

Figure 7.1-13 Low Pressure Carbon Dioxide Storage Unit

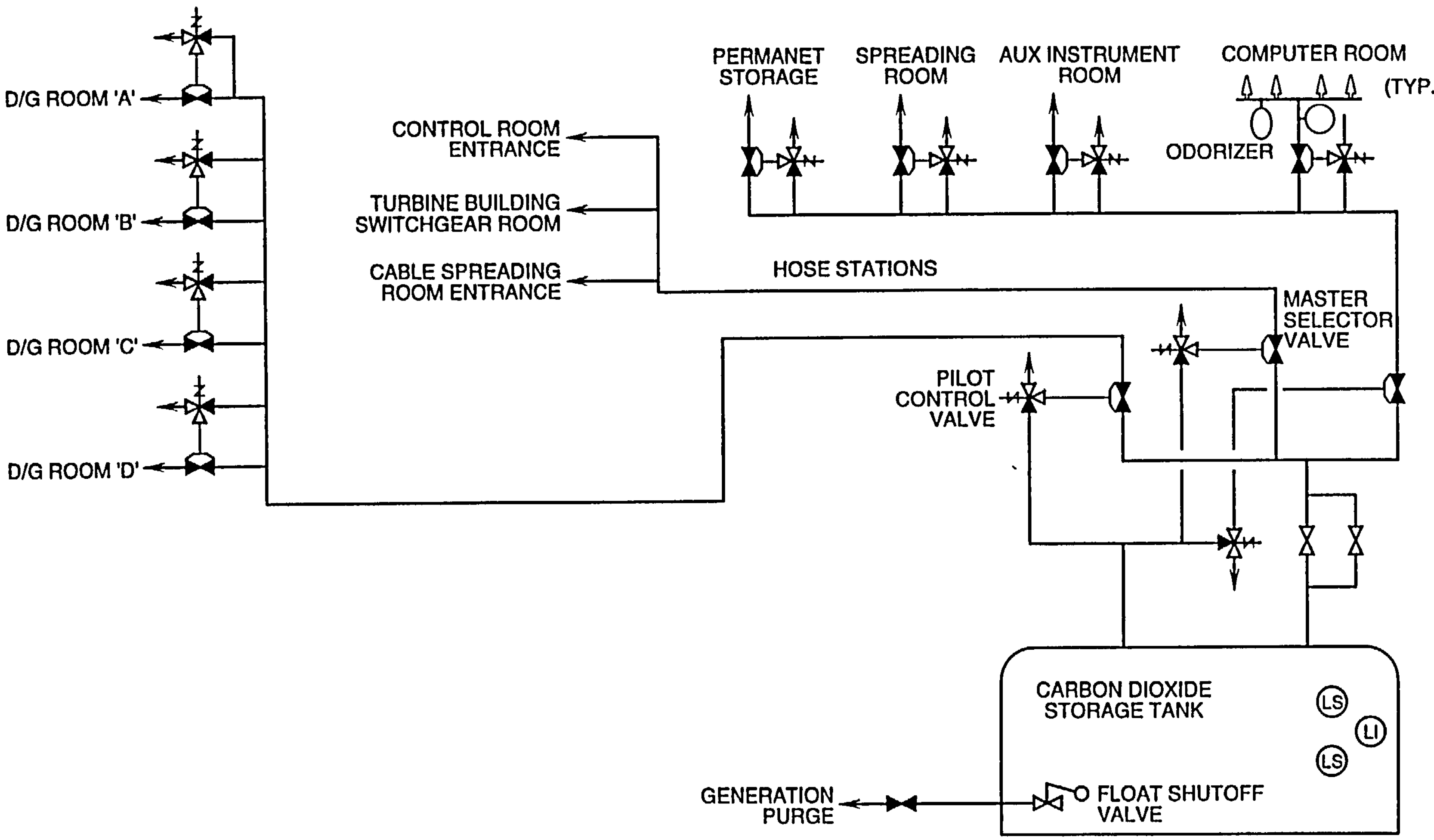

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Figure 7.1-14 Low Pressure Carbon Dioxide System

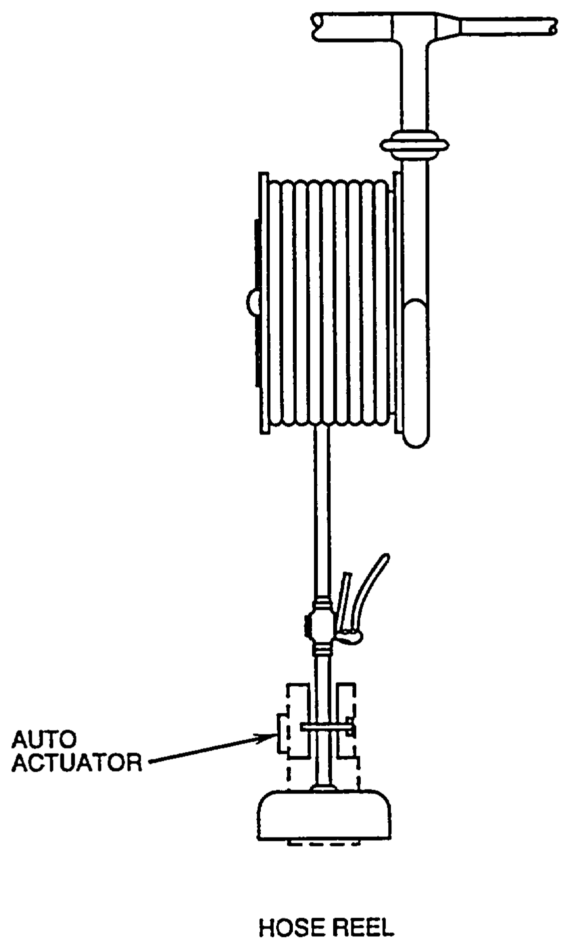

Figure 7.1-15 Hosereel Station

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7.2 Oyster Creek Log Summary

Learning Objectives :

1. Explain why this event is only a problem for BWR/2 product lines.
2. List the two areas of the reactor vessel that are monitored to determine vessel water level.

7.2.1 Introduction

Oyster Creek is a BWR/2 plant rated at 1930 MWt and 670 MWe. At the time of the incident, May 2, 1979, the unit was operating at 98 percent power. At approximately 1350 hours an inadvertent reactor high pressure scram occurred during surveillance testing on the isolation condenser high pressure initiation switches.

The technician performing the test was in the process of verifying that the sensing line excess flow check valve was open when the scram occurred. The scram was attributed to a momentary simultaneous operation of pressure switches due to a hydraulic disturbance associated with valve manipulations required by procedure to verify the position of the excess flow check valve. The hydraulic disturbance also caused a momentary trip of the isolation condenser initiation switches. Two of the four reactor high pressure scram sensors share a common sensing line with the isolation condenser initiation switches being tested. These sensors were not closed long enough to initiate an automatic initiation of the isolation condensers since a time delay is involved in the initiation logic. However, these sensors are also used in the automatic recirculation pump trip logic which did operate (no time delay involved).

One of two startup transformers, SB, was out of service to perform an inspection of its associated 4160 volt cabling (permitted by Technical Specifications). Transformer SB supplies off site power to one half of the station electrical distribution system (Figure 7.2-1) when power is not available through the station auxiliary transformer. The 4160 volt busses which receive power from SB are 1B and 1D. Buss 1D supplies power to certain redundant safety systems and is designed to be powered from the number 2 diesel generator in the event power is not available from either the auxiliary or startup transformer. Buss 1B supplies 4160 volt power to non-safety related systems and hence, does not have a diesel backup power source.

One of the five recirculation loops, loop D, was not in service due to a faulty seal cooler cooling coil. The pump suction valve was open, discharge valve closed, and discharge valve bypass open. No other systems and/or components important to the event were out of service.

7.2.2 Event Description

A reactor scram occurred for the reasons described above, coupled with a simultaneous trip of the four operating recirculation pumps. The control room operator verified that all control rods inserted and proceeded to drive in the IRMs and SRMs. At this time, 4160 volt power was being supplied from the main turbine generator via the auxiliary transformer. Steam flow started decreasing due to loss of heat production. Feed flow remained at full flow rate.

The turbine generator subsequently tripped on reverse power as designed which initiated an automatic transfer of power to the startup transformers. Power to busses 1A and 1C successfully transferred from the auxiliary transformer to startup transformer SA. Since SB was out of service at this time, power was lost to busses 1B and 1D which caused an automatic start of the number 2 diesel generator.

Loss of power to bus 1B resulted in loss of condensate pumps and feedwater pumps B and C. Although power was available to the A condensate and feedwater pumps, the A feedwater pump

pump failed to start due to a tripped overload on the auxiliary oil pump which provides an interlock in the feedwater pump starting sequence. The auxiliary oil pump was started locally followed by starting the A Feedwater pump. Indicated water level increased to a level corresponding to 13 feet 8 inches above the top of the core. The operator now recognized that all five recirculation loop discharge valves were closed and indicated water level and actual water level may not have been the same.

The A recirculation pump was placed in service which removed the disparity between the water level instruments. Indicated water level dropped approximately three feet to 11 feet 4 inches above the top of the fuel. Recirculation loop A temperature increased from 375°F to 465°F after starting the pump. In addition, the low-low-low water level condition cleared at this time.

7.2.3 Areas of Concern

The need for better communication between the downcomer region and the core region was apparent. Therefore, a Technical Specification revision was issued which required that at least two recirculation loops will be lined up with their respective suction and discharge valves open during all modes of plant operation. The requirement was so important that it was placed in the Safety Limit section of Technical Specification.

7.2.4 Corrective Actions

A confirmatory order, dated March 14, 1983, was issued that required an interlock system for the recirculation pump loops. In lieu of the interlock, Oyster Creek received approval for the installation of an alarm system that would provide annunciation when the fourth loop was isolated. This modification was required to be completed by October 1986.

7.2.5 Related subsequent Safety Limit Violation

While performing maintenance on the Reactor Building Closed Cooling Water System (RBCCW) on September 11, 1987, at 2:30 a.m., an operator identified leakage within the system and proceeded to isolate one of the two recirculation loops which was in service at the time. This is a violation of Technical Specifications 2.1, Fuel Cladding Integrity, which requires two recirculation loops to have their suction and discharge valves in the full open position during all modes of operation. Within seconds the operator placed one of the three isolated loops into operation. The total elapsed time with less than two loops in service was approximately 2 and one half minutes. The plant was in shutdown and on shutdown cooling with reactor temperature about 140 °F prior to the event.

7.2.6 Summary

Unlike other BWRs the BWR/2 reactor vessels do not have direct communication from the annulus region to the core inlet plenum. Water must exit the reactor vessel via recirculation loops and then reenter the vessel bottom head.

Table 7.2-1 Oyster Creek Reactor Vessel Levels

	Vessel Elevation	Distance Above TAF	Yarway	GEMAC	Barton
Flange	660"				
Steam Line	591"				
Top of Steam Separators & Indication	539"	15'6"	100"		130"
Turbine Trip	529"		90"		
Normal Level	519"	13'10"	80"	6'4"	
Low Level Scram	490"	11'5"		51"	
Bottom of Steam Separators	485"				
Bottom of Dryer Skirt	477"				
FWCS Inst. "0"	443"			0"	
Low-Low Level	439"	7'2"	0"		
Feed Line Nozzel	422"				
Low-Low-Low Level	418"				0"
Core Spray Nozzle	408"				
TAF	353"				
Vessel "0"	0"				

Table 7.2-2 Oyster Creek Plant Information

MWt	1930
MWe	670
Steam Flow/Feed Flow	7.33×10^6 lb/hr
Core Flow	73.6×10^6 lb/hr
RFPs	3 motor driven pumps (33% each)
BPV capacity	45%
Isolation Condensers	2 (3% steam flow each)
Containment	Mark I
SRVs (ADS)	4
Safety Valves	15
Recirculation System	5 loops, 1 variable speed pump each, NO Jet Pumps
Decay Heat Removal	Shutdown Cooling System
Low Pressure ECCSs	2 - 100% Core Spray Systems
High Reactor Pressure	1050 psig
ATWS-RPT	1060 psig
IC Auto Initition	1060 psig or low-low level

Table 7.2-3 Sequence of Events

1350 hrs	Oyster Creek (BWR/2) was operating at base load conditions of 1895 MWT (98% of rated) using 4 of the 5 recirculation loops. Equipment out of service included the D recirculation loop (suction valve open, discharge valve closed, and discharge bypass valve open) and one startup transformer (for inspection of its cabling). An instrument technician was performing surveillance testing of the isolation condenser pressure switches.
1351(0s)	High pressure reactor scram and simultaneous trip of all operating recirculation pumps.
1351 (13)	Turbine generator trip on low load. Diesel generator #2 started. The B and C condensate pumps and the B and C RFPs tripped on undervoltage and the A RFP tripped on low suction pressure.
1351 (13.6)	Reactor water level at low level scram setpoint.
1351 (31)	Diesel generator #2 closed into the 1D switchgear. A second CRD pump was started.
1351 (43)	Reactor water inventory continuing to decrease. Operator closed MSIVs.
1351 (59.6)	Reactor mode switch was transferred from run to refuel.
1352 (16)	The B isolation condenser was placed in service. The operator closed the A and E recirculation loop discharge valves. [It is postulated that the B and C recirculation loop discharge valves were also closed at this time.]
1352 (30)	Reactor low water level alarm cleared.
1352 (36)	The B isolation condenser return valve was fully open.
1353 (52)	Low low low reactor water level instrument trip.
1354 (6)	All recirculation loop discharge valves were fully closed.
1355 (10)	The B isolation condenser was removed from service.
1355 (30)	Reactor pressure increasing.
1358 (30)	A & B isolation condensers placed in service.
1359 (48)	The B isolation condenser was removed from service. Indicated water level dropped from 14.4 ft. above TAF to 13'8" above TAF.
1400	The four low low low level indicators were verified locally to be below their trip point
1404 (30)	The low low low level indicators continue to read below their trip point.
1411 (12)	The A isolation condenser was removed from service.

Table 7.2-3 Sequence of Events

1415 (48)	The A isolation condenser was used several more times to control reactor pressure.
1422 (54)	The C recirculation pump was started.
1424 (33)	The C recirculation pump was shutdown after indicated water level dropped about 3 feet in less than 2 minutes. The C recirculation pump was isolated. Started the A RFP.
1427 (48)	The A recirculation pump was placed in service at a flow rate of 1.9×10^4 GPM. Indicated water level dropped about 3 feet to 11'4" above the top of active fuel. The low low low water level condition was cleared at this time.
1431	Steps were initiated to bring the reactor to a cold shutdown condition.
1451	The B startup transformer was returned to service and the B switchgear was re-energized.
2228	Cold shutdown condition was achieved.

Table 7.2-4 OYSTER CREEK REACTOR LEVEL PROBLEMS

Events Chronology

DATE	EVENT
May 2, 1979	Added new SAFETY LIMIT to T.S. requiring that a minimum of 2-loops remain open, e.g. suction & discharge valves fully open, during all Operational Conditions.*
1979-1980	Refueling Outage: Installed a Fuel Zone LI & Recorder in the control room. This provides accurate <u>core</u> water level indication when all RR pumps are stopped.
1980	NUREG-0737: Required plants w/o jet pumps (except Humboldt Bay) to install interlocks that would assure that a minimum of 2-recirc loops valves would remain open during *all operational conditions* other than cold shutdown. However, an agreement was reached between the NRC and OC to incorporate an alarm systems instead of an interlock system.
March 14, 1983	Confirmatory Order: NRC decreed that the licensee meet 0737 requirements as stated above.
April 23, 1986	The NRC published a proposed T.S. revision in the Federal Register that would permit the installation of an alarm unit, in lieu of interlocks, that would activate when the 4th consecutive RR loop became isolated.
Sept. 11, 1987	A control room operator closed one of the two remaining open recirc pump discharge valves. The operator immediately went to OPEN on a discharge valve in another loop (valves can not be throttled but will go to the position selected by the operator before he can reverse its direction). An alarm was received in the control room when the 4th loop discharge valve became isolated. **

* Safety Limit Requirement - Fuel Cladding Integrity: At least 2-recirculation loops will be lined up as described. This will ensure that an adequate flow path exists from the annulus between the pressure vessel wall and core shroud, to the core. This provides good communication between these areas thus assuring that measured reactor water level is truly indicative of actual water level in the <u>core</u>.

** Subsequent to an investigation of this event:

1. Portions of Sequence of Alarms tapes were thrown into a commode, e.g. That portion referring to the RR pumps discharge valves closed alarms.

2. Two supervisors and three control room operators were suspended from duty pending outcome of the investigation.

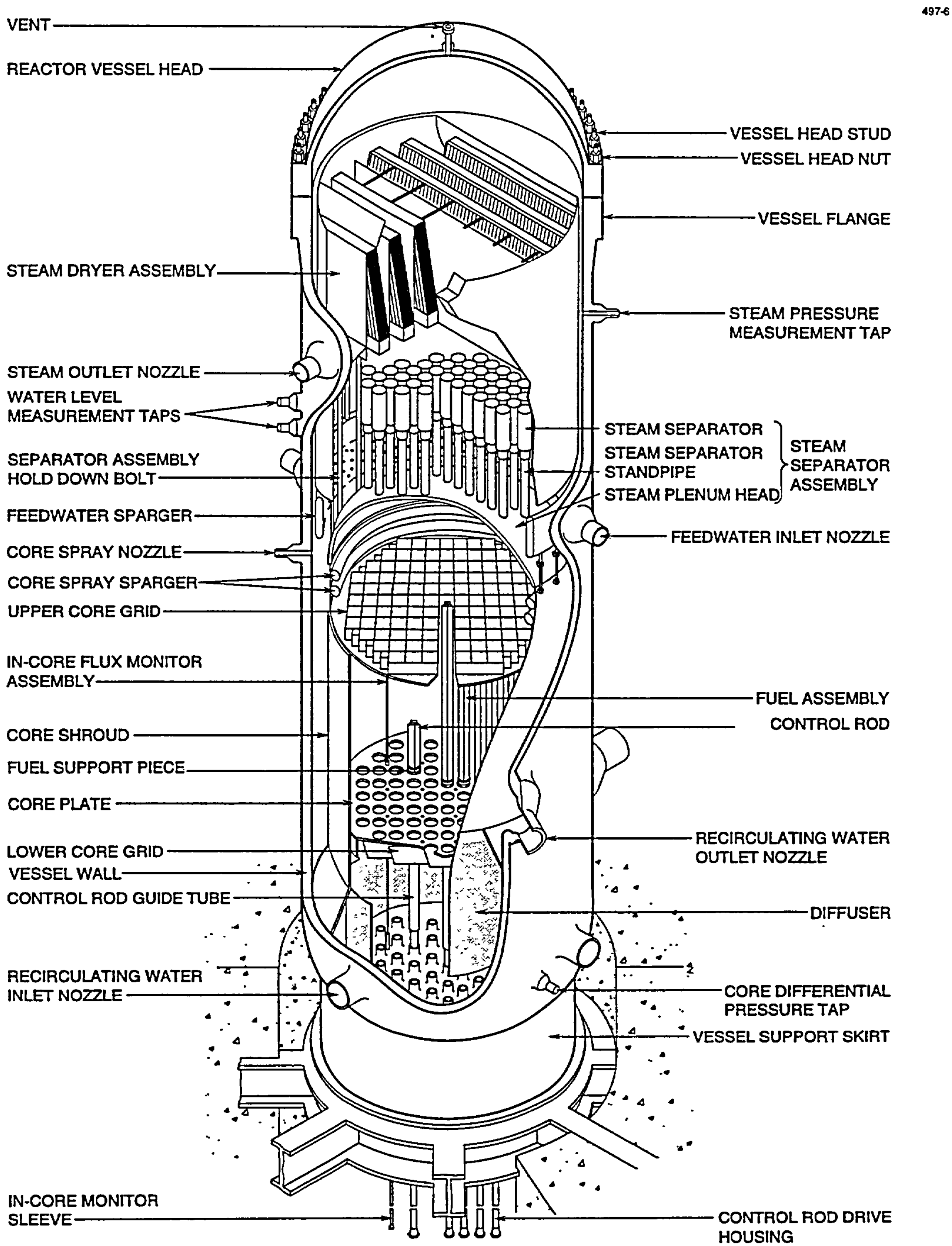

Figure 7.2-1 BWR/2 Reactor Vessel

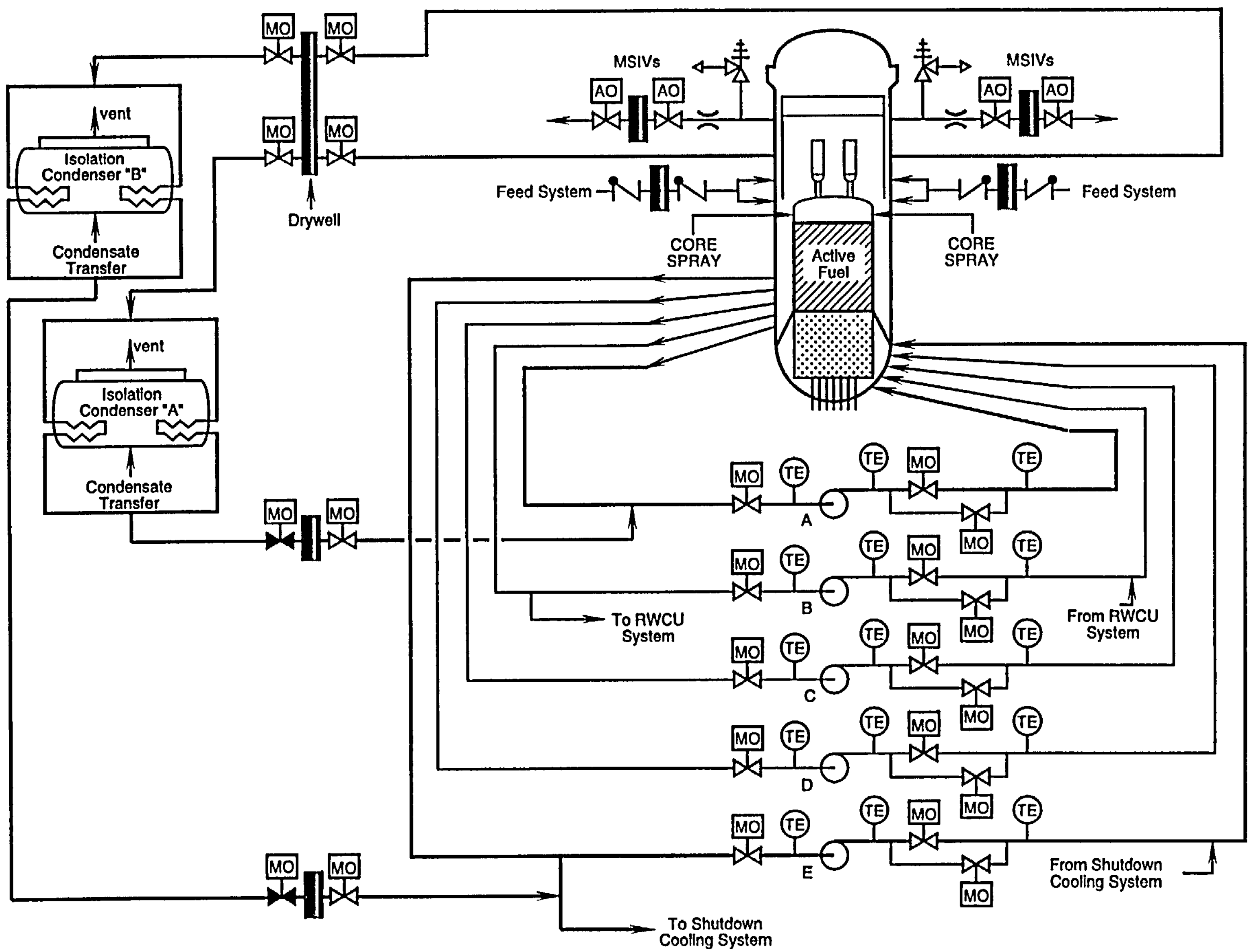

Figure 7.2-2 BWR/2 Isolation Condenser and Recirculation Systems

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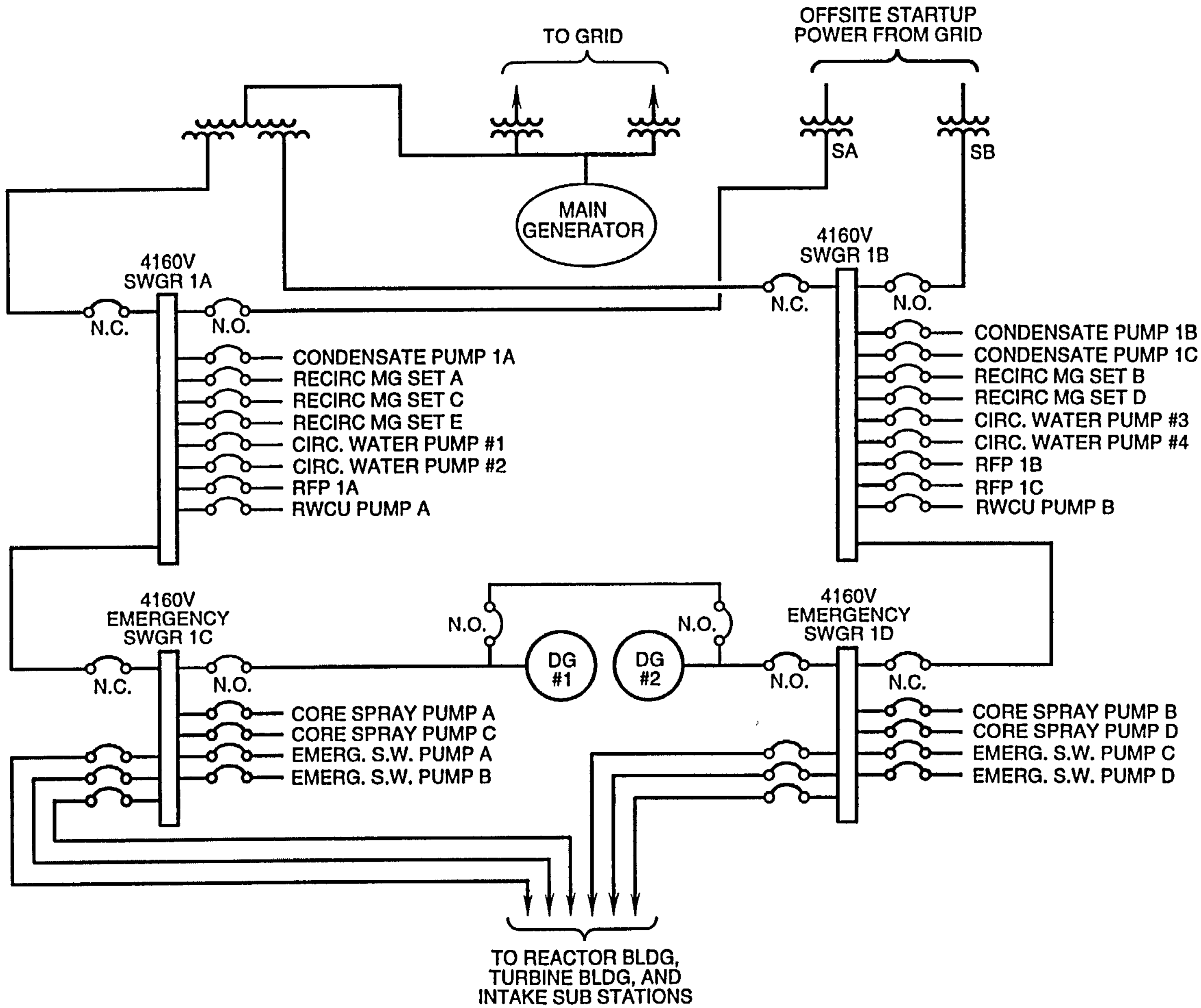

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Figure 7.2-3 Oyster Creek Electrical Distribution

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7.3 Dresden Log Summary

Learning Objectives :

1. Explain the need for a maximum combined flow limiter in the Electro Hydraulic Control System.

2. Explain the term half isolation.

3. Explain why isolation valve control switches must be in the closed position prior to resetting the isolation signal.

4. Explain the need to reset a reactor scram when the condition has cleared.

7.3.1 Introduction

Dresden Unit 3 is a BWR/3 plant rated at 2527 MWt and 809 MWe. At the time of the incident, September 19, 1985, the unit was operating at 83 percent reactor power. At approximately 1339 hours, Dresden Unit 3 tripped from an average power range monitor (APRM) high-high flux scram. The trip resulted from a pressure transient that was caused by closure of the turbine control valves. During the scram recovery, difficulty was encountered in resetting reactor protection system (RPS) channel B. Also during the recovery, the scram discharge volume (SDV) vent and drain valves opened while the control rod drive scram inlet and outlet valves on every CRD hydraulic control unit were open. This resulted in the release of reactor vessel water inventory to the reactor building.

Several days before the Unit 3 scram had occurred, the Instrument Maintenance (IM) department had installed a multi-point recorder to various points in the Electro Hydraulic Control (EHC) circuitry. Unit 3 had been experiencing problems with the Economic Generation Control (EGC) portion of the EHC system and to identify the cause of the problems the multipoint recorder was installed to monitor certain parameters. The IM department was successful in identifying the EGC problem and decided to remove the recorder from the EHC sample points. While removing the recorder leads from the EHC control circuit, an IM mechanic accidentally moved a circuit card, momentarily disrupting the maximum combined flow portion of the EHC circuit. This caused a zero maximum combined flow output voltage signal resulting in closure of all the turbine control valves and bypass valves. The closure of the control valves caused a reactor pressure spike, resulting in a high neutron flux and a subsequent APRM high-high flux scram.

7.3.2 Failure of Scram Reset

When the scram occurred, the Unit 3 reactor operator followed scram procedure DGP 2-3. When moving the reactor mode switch to the "refuel" position, it was left partially between the "shutdown" and "refuel" position. This generated a reactor mode switch scram signal on the 'B' RPS channel which could not be reset. The last time the operator attempted to reset the reactor (approximately ten minutes after the scram) he was only able to reset the 'A' RPS channel. Approximately one hour and sixteen minutes after the scram, the Unit 3 operating engineer noticed the mode switch in the midposition. When the mode switch was fully placed in the "refuel" position, the reactor operator was able to fully reset the reactor scram signal.

7.3.3 Scram Discharge Volume Air Header Failure

The scram air header is designed to supply control air to the SDV air operated vent and drain valves and all 177 CRD scram inlet and outlet valves. During a reactor scram, the air supply to the SDV header is isolated by the SDV backup scram valves. The air within the isolated portion of the header is vented to the Reactor Building atmosphere by each control rod drive hydraulic control unit scram pilot valves and the scram dump valves, Figure 7.3-1. The backup scram valves

7.3.7 PRA Insight

In addition to providing power to the reactor protection system, the RPS buses provide power to the primary containment isolation control system (PCIS). This system operates valves as required to isolate the reactor vessel and/or primary containment to conserve coolant inventory and prevent the release of radioactive materials. Loss of power to RPS bus 'B' de-energizes all 'B' train logic in the isolation control system and results in the isolation of among other things the Reactor Water Cleanup System and the shutdown cooling mode of the Residual Heat Removal (RHR) System.

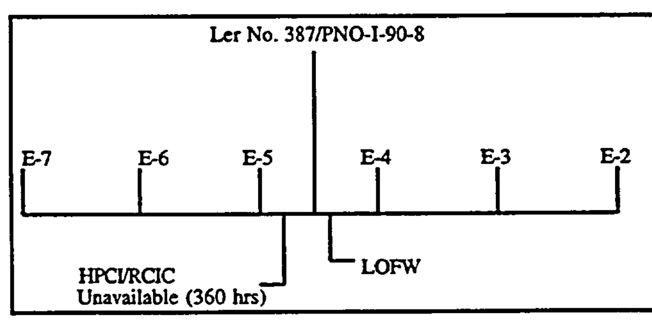
On February 3, 1990 an event occurred at Susquehanna Unit 1 that conveys the important interrelationship between the RPS and the PCIS. Unit 1 was shutdown on February 1, 1990 for maintenance. Two days later a test of the alternate power supply to RPS bus 'B' was conducted. When normal power was secured, the alternate supply failed to close in on the bus. The loss of power resulted in isolation of certain valves controlled by this system including a RHR shutdown cooling suction supply valve. With normal shutdown cooling lost, the reactor water temperature began to increase. Operators stopped the coolant temperature rise at 252^{0}F by opening three Safety Relief Valves (SRVs). Makeup water was provided by the control rod drive pump.

An event tree model of sequences to core damage was developed considering the potential unavailability of mitigating features described in Susquehanna's procedures. This event tree (Figure 7.3-4), addresses RPV makeup via the control rod drive, condensate, core spray, or low pressure coolant injection systems. If the SRVs are used, then suppression pool cooling is also assumed required.

Figure 7.3-4 includes the following core damage sequences:

- Successful use of the SRVs and SP cooling for heat removal, but failure to provide RPV makeup via the CRD, condensate, core spray and LPCI sys-tems.
- Failure of SP cooling following successful opening of the SRVs.RWCU is successful but makeup via the condensate system fails.
- Failure of SP cooling following successful opening of the SRVs. RWCU fails to provide letdown/heat removal.
- Similar to sequence 2 except the SRVs fail to open.
- Similar to sequence 3 except the SRVs fail to open.

The conditional probability of subsequent core damage associated with the event (LER 387/PNO-I-90-8) is conservatively estimated to be 4.1 x 10^{-5}. The relative significance of this event compared to the postulated events at Susquehanna is indicated below:



7.3.7 Summary

In the Dresden event, the output of the Maximum Combined Flow (MCF) limiter of the EHC logic failed to zero. This closed all turbine valves and BPVs. The purpose of the MCF is to limit the maximum amount of steam the turbine and BPVs can remove from the vessel if the pressure

Table 7.3-1 Sequence of Events

1330	Unit 3 at 83 percent power - Normal operation.
1339	APRM high flux scram occurs.
(+1s)	Maximum combined flow alarm received.
(+5s)	Approximately 20 control rods found at position 02. Received Group II and III containment isolation.
(+6s)	The reactor operator manually scrams the unit per the scram procedure and takes scram procedure actions.
1340	The reactor operator resets Group II and III isolation.
1344	The Reactor Water Cleanup System restarted and establishes blowdown to the main condenser.
1349	The control room operator attempted to reset the reactor scram but only the 'A' channel would reset.
1351	The control room operator notes that the scram inlet and outlet valves did not close in addition to a low SDV air header alarm.
1355	The Unit 3 Shift Foreman investigated the air header problem and reported a pressure of only 38 psig (Normal pressure 83 psig).

Table 7.3-1 Sequence of Events

1412	Received a steam tunnel high temperature alarm (channel D) accompanied with a group I half isolation.
(+15s)	High temperature in steam tunnel verified at 160°F.
1415	The reactor operator received a RWCU heat exchanger relief valve leakage alarm and isolated the RWCU system. The Unit 3 Shift Foreman was dispatched to investigate the leakage alarm.
1439	The Shift Foreman notified the control room operator that steam is present in the RWCU pump room, shutdown cooling pump room, and the torus basement.
1440	The control room operator was notified that steam was coming from the SDV vent and drain valves. The control room operator noticed the vent and drain valves open, then manually closed them from the control room.
1441	The steam tunnel high temperature alarm and isolation were cleared and reset.
1455	While trying to identify the cause of the reactor half scram reset problem, the Unit 3 Operating Engineer discovered the reactor mode switch in a mid-position between the shutdown and refuel modes. The mode switch was placed in the refuel position and the 'B' RPS channel reset

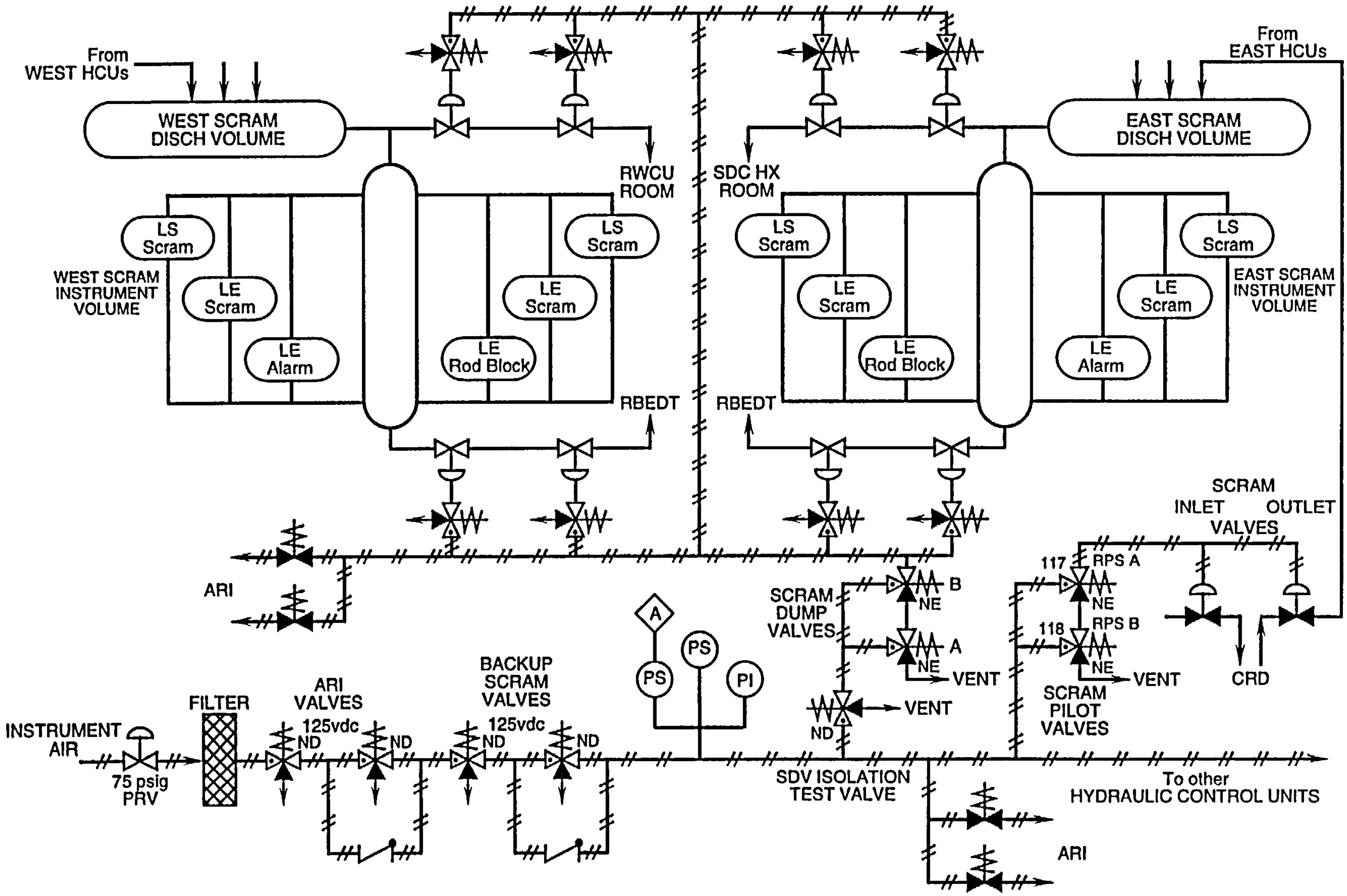


Figure 7.3-1 Dresden Scram Discharge Volume (SDV)

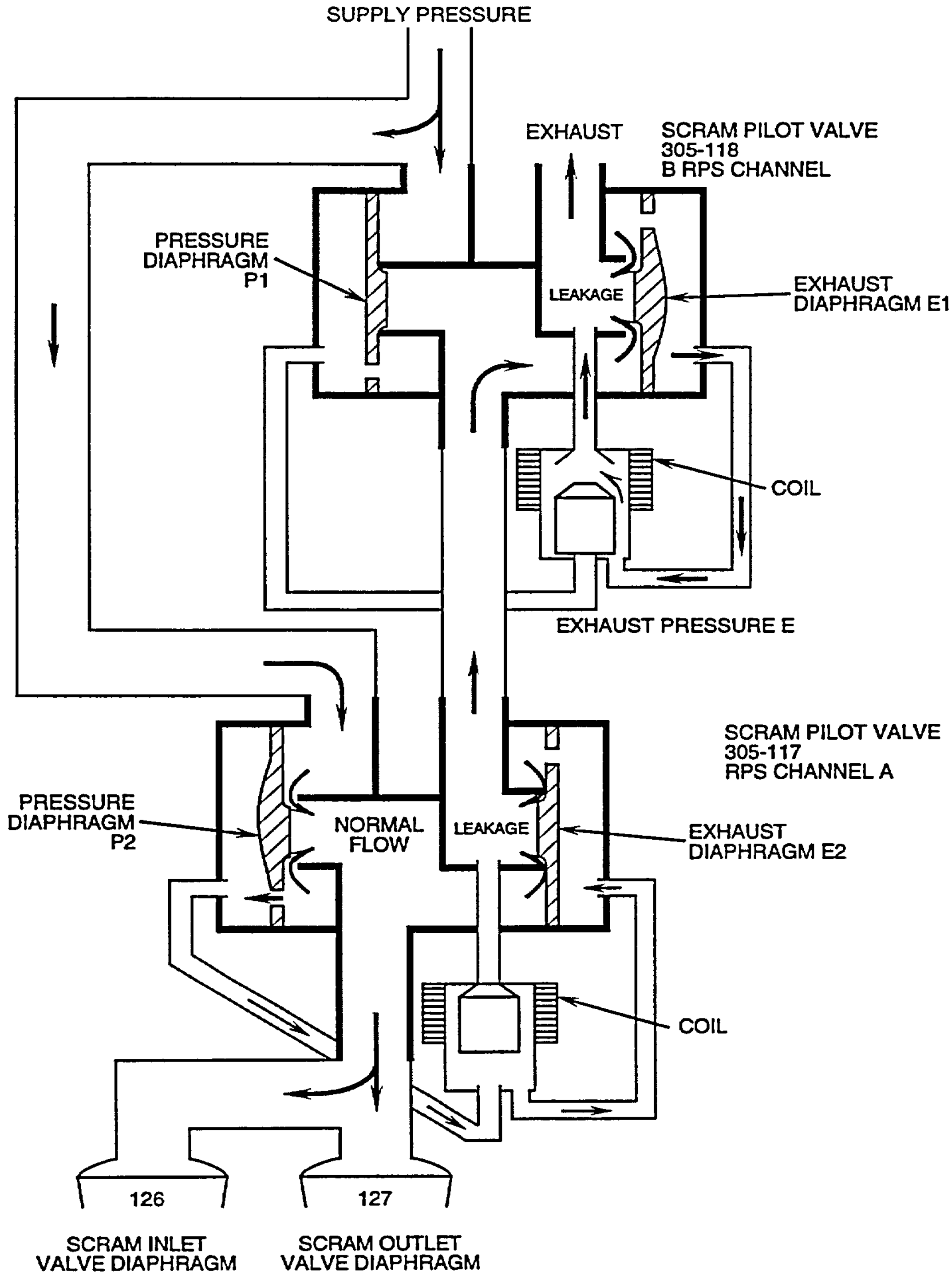


Figure 7.3-2 Scram Pilot Valve Configuration with "A" RPS reset and B Tripped

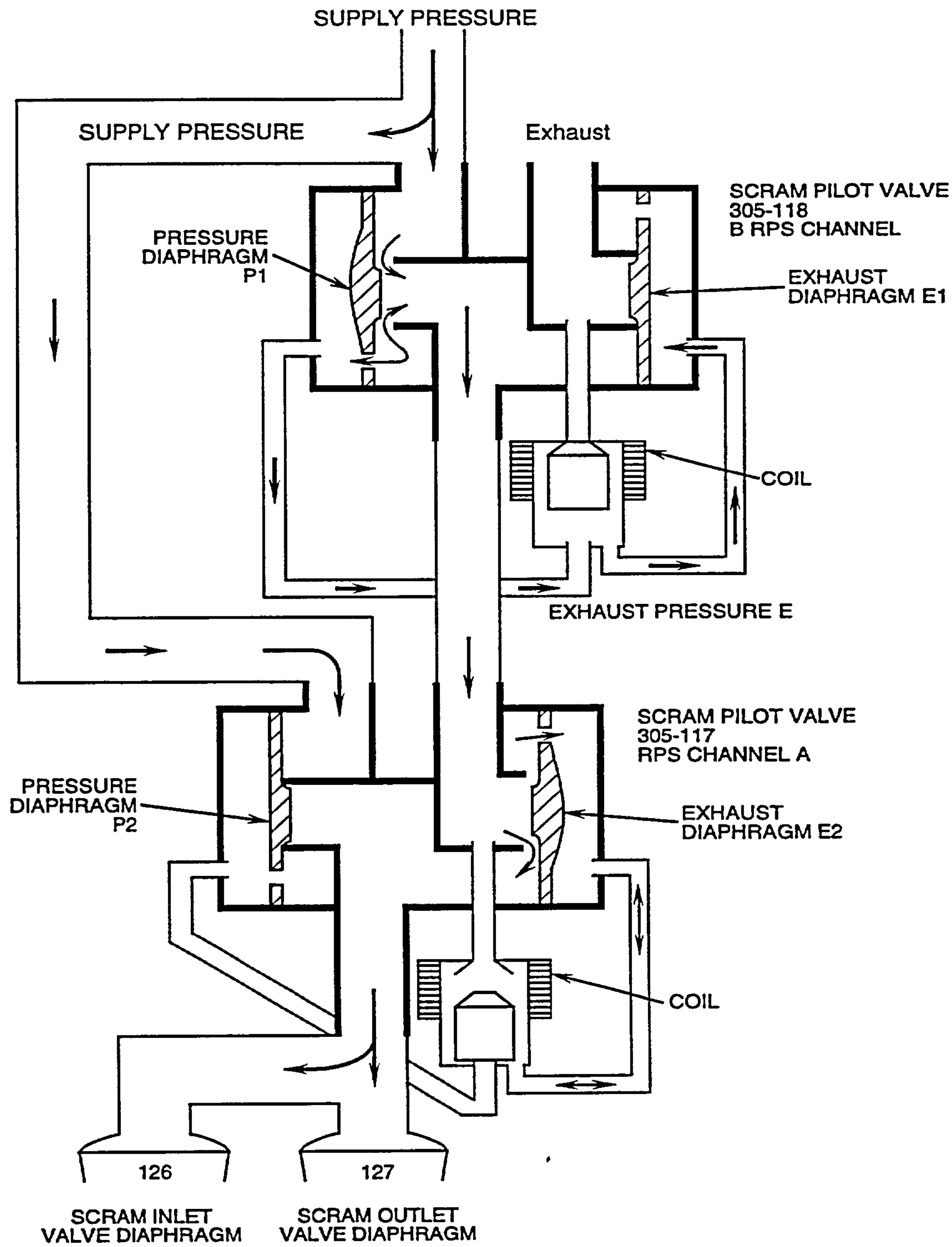


Figure 7.3-3 Scram Pilot Valve Configuration with "B" RPS reset and A RPS Tripped

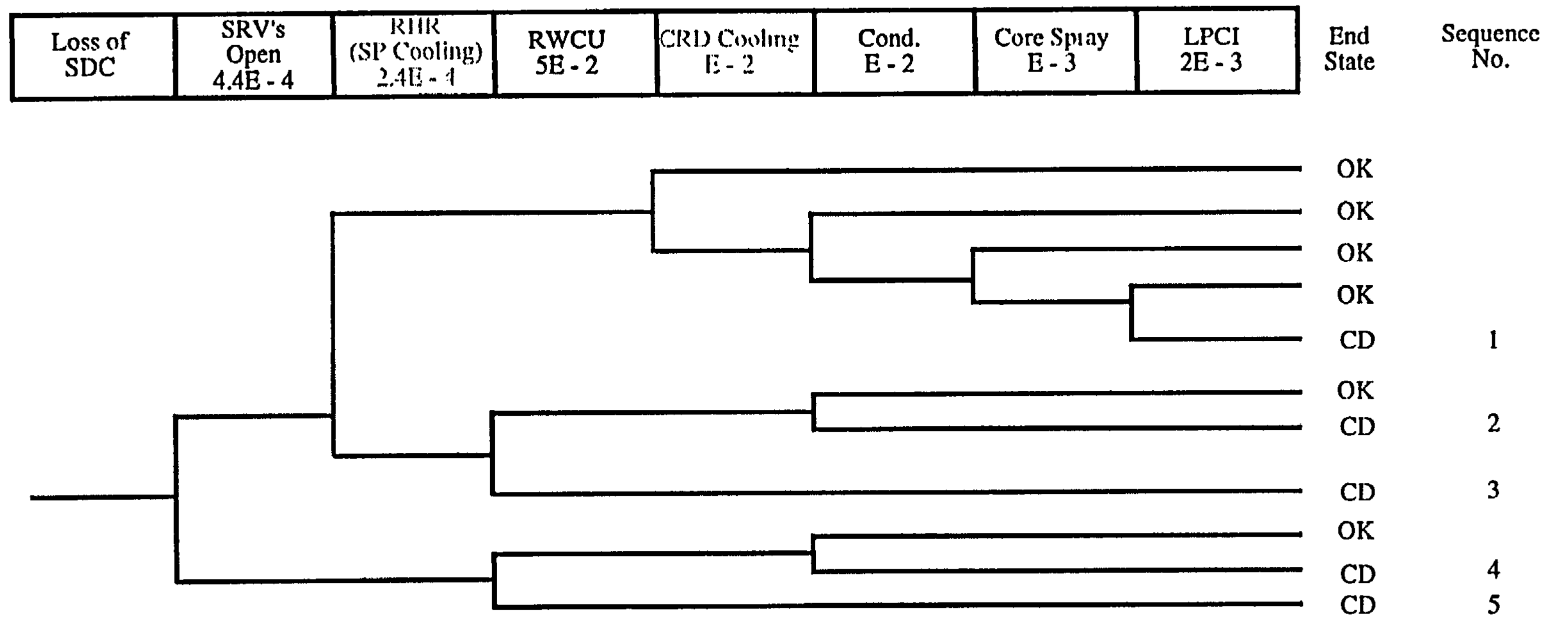


Figure 7.3-4 Event Tree for Loss of Shutdown Cooling at Susquehanna 1

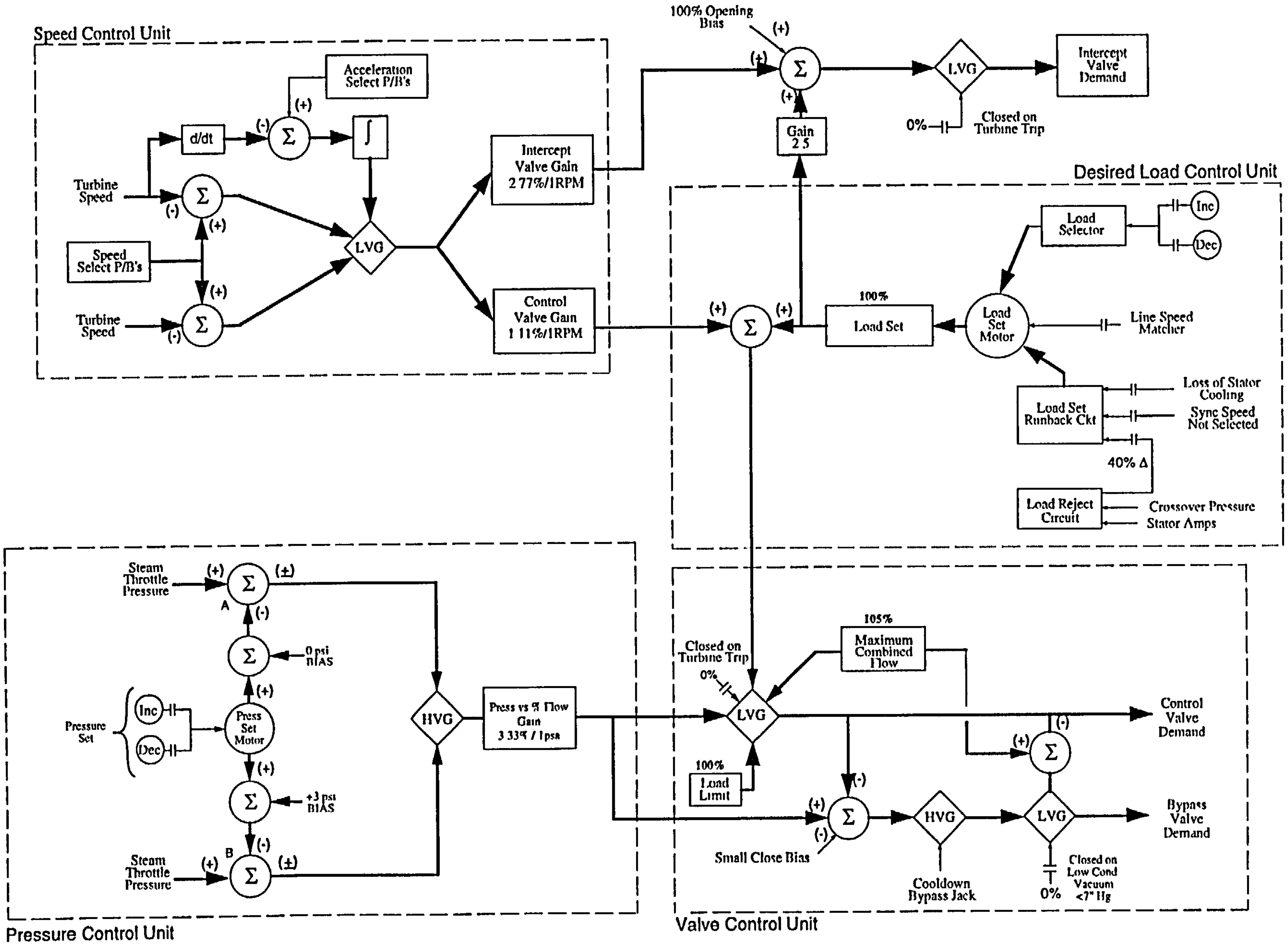


Figure 7.3-5 Electro Hydraulic Control System Logic

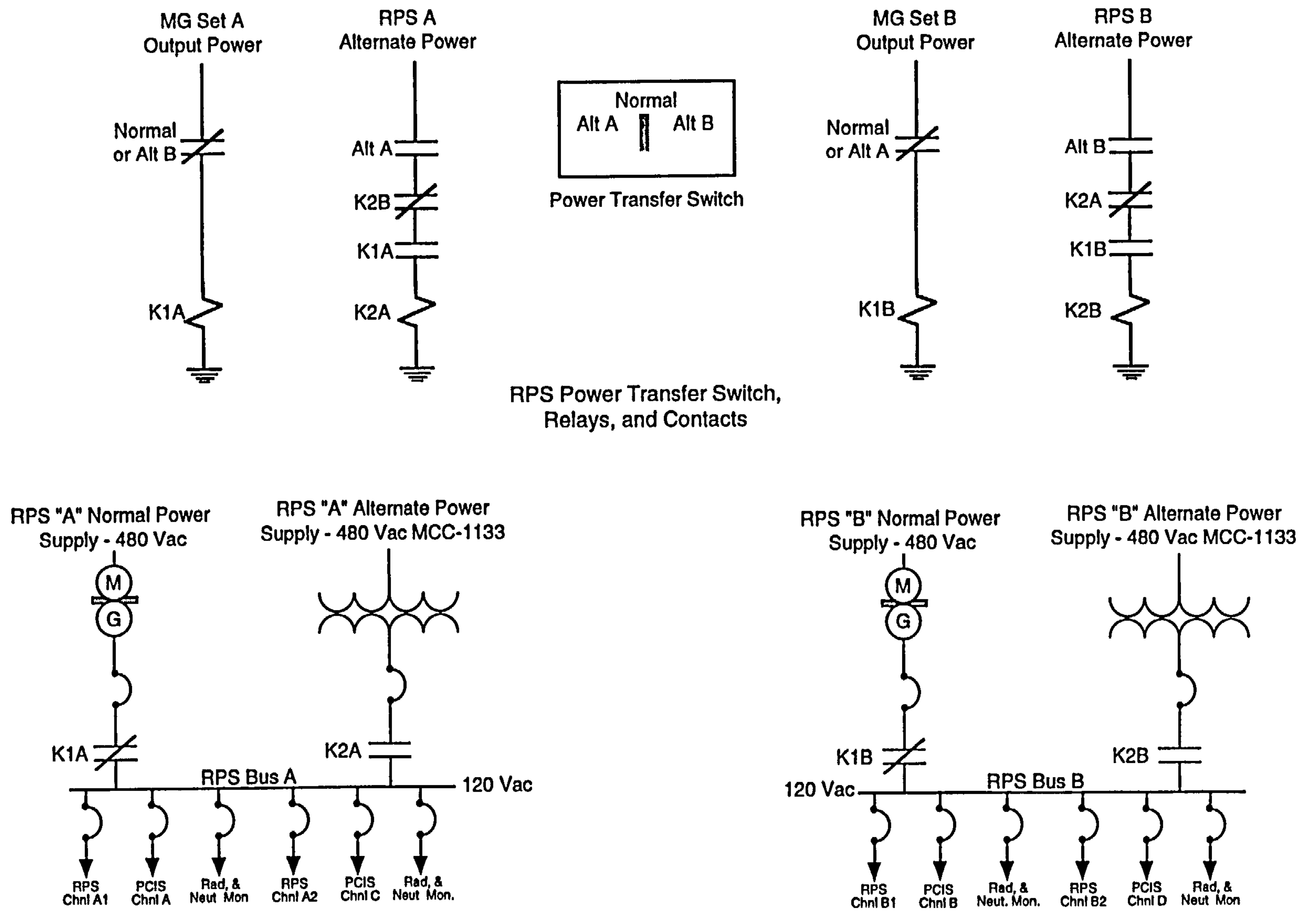


Figure 7.3-6 RPS Power Supply